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CHAPTER 7: Estimated Costs of Low-Sulfur Fuels

7.1 Nonroad Fuel Volumes

7.1.1 Overview

This section describes how the estimates of diesel fuel demand for land-based nonroad engines, locomotives, and marine vessels, which will be directly affected by the proposed rules, were determined. Volumes are provided for various geographic regions of interest. The discussion focuses on how these volumes were developed for 2000 and 2008, and then describes how the estimates for other years were produced. This section also describes diesel fuel supply volumes for 2008, which are used in the economic assessment.

Of course, only the amount of high-sulfur fuel used by land-based nonroad engines, locomotives, and marine vessels will be directly affected by today's proposal. In this analysis, the basic approach to estimating this fuel volume is to: 1) find the total diesel fuel demand in each category, 2) determine the respective amount of this fuel which already meets the highway fuel standards, and 3) subtract the low-sulfur volume from the total diesel fuel demand to yield the volume of high-sulfur diesel in the category.

Estimating diesel fuel consumption for the engine categories covered by the proposal also requires a basic understanding of the fueling practices for non-highway equipment. Generally, these equipment types are capable of using either high-sulfur diesel fuel or low-sulfur fuel that complies with the EPA highway diesel sulfur regulations. This latter fuel type may be used in non-highway applications for a variety of reasons. First, some equipment may be refueled at service stations where only low-sulfur, highway compliant fuel is available. Second, high-sulfur fuel may not be available due to limitations in the distribution or storage systems in some areas or during certain times of the year. Third, operators may choose to use low-sulfur diesel fuel based on some real or perceived benefit such as improved engine durability.

The estimates of diesel fuel volumes used in this analysis are principally based on the *Fuel Oil and Kerosene Sales 2000* (FOKS) report, which is produced by the Energy Information Administration (EIA).[1] This report represents the most detailed, comprehensive distillate fuel demand study available. The report contains estimates of distillate fuel sales for highway vehicles and 10 non-highway end uses. Unfortunately, the values reported in FOKS for the non-highway categories can not be used directly in this analysis, because it does not always report fuel volumes into the specific equipment types or diesel fuel grades that will be affected by the proposed rules.

As explained in detail in the next section, EPA in consultation with EIA identified six of the broadly reported categories in the EIA FOKS report as being relevant to this analysis. In addition, EPA found that EIA's railroad category contained distillate fuel used in both land-based nonroad engines, e.g., rail maintenance equipment and locomotives. Finally, EPA identified

EIA's vessel bunkering category as containing both recreational and commercial distillate fuel. The categories and end uses of interest from the EIA FOKS report are generally shown in Table 7.1-1.

Table 7.1-1
Application of EIA FOKS End Use Categories to EPA Off-Highway Categories

FOKS Category	EPA Proposal Categories		
	Land-Based Nonroad	Locomotives	Marine
Farm	X		
Other Off-Highway			
Construction	X		
Other	X		
Industrial	X		
Commercial	X		
Oil Company	X		
Military	X		
Railroad	X	X	
Vessel Bunkering (Marine)			X

Each of these topics is discussed in detail in the remainder of this section, along with the resulting estimates of high-sulfur diesel fuel that would be affected by the proposed rules.

7.1.2 Diesel Fuel Demand by PADD for 2000

High-sulfur diesel fuel is calculated by subtracting the low-sulfur diesel fuel demand from the total diesel fuel demand in the respective category. A common element in determining the volume of low-sulfur fuel is the amount, or percentage of low-sulfur, highway compliant diesel fuel that is spilled over into each of the non-highway end-use categories. Therefore, this section begins by identifying the amount of spillover for the various end uses of interest, and progresses to applying that information to estimate the volume of high-sulfur diesel fuel in each of the end-use categories.

7.1.2.1 Highway Diesel Fuel Volumes and Highway Spillover

Spillover is defined as the total volume of low-sulfur, highway compliant fuel supplied into the U.S. minus the volume of this fuel that is consumed (i.e., demand) by highway vehicles. The of volume of highway compliant fuel supplied to each PADD is provided in the Petroleum Supply Annual 2000, which is published by the Energy Information Agency.[2] The values from that report have been converted from barrels to gallons using a conversion factor of 42 gallons per barrel. The volume of highway fuel demand is provided in the EIA FOKS report.

Table 7.1-2 shows the spillover volumes in each of the five PADDs based on the above information.

Now that the total volume of low-sulfur diesel spillover is known, the next step in determining the low-sulfur spillover percentage is to find the total volume of diesel fuel consumed by all non-highway end-uses. The EIA FOKS report provides distillate sales numbers for the various off-highway end-use categories that could contain spillover fuel. Some of the distillate fuel grade categories contained in the report are quite broad in scope, making it difficult to accurately determine only the fuel volumes that are clearly interchangeable with the diesel fuel grades affected by the proposed rules. For example, certain end-use categories report distillate fuel oil or total distillate. These specifications may contain incompatible fuel types such as No. 4 fuel oil that is used in commercial burner applications. When more specific fuel grade information was unavailable, the volumes for these broader specifications are used to determine the total “potential” volume of non-highway fuel consumption. Fortunately, the volumes of these broad specification distillate fuels are relatively small compared to the total volumes of better defined diesel fuel grades. A detailed table showing how the potential non-highway diesel fuel volumes were determined is shown in Appendix 7A. The relevant fuel demand volumes are summarized in Table 7.1-3.

Table 7.1-2
Highway Diesel Fuel Spillover Volumes by PADD (million gallons)

Highway Diesel Category	1	2	3	4	5	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Supply	11,257	12,939	6,947	2,213	5,892	NA	2,633	NA	NA
Demand	10,228	11,141	5,644	1,475	4,643	NA	2,633	NA	NA
Spillover	1,029	1,799	1,303	738	1,250	NA	0	NA	NA

NA = Spillover volume is not used to determine the spillover percentages for these areas as explained later in Section 7.1.2.1.

Table 7.1-3
Potential Non-Highway Diesel Fuel Demand by PADD (million gallons)

End Use	PADD								
	1	2	3	4	5	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Residential	5,399	629	1	39	137	82	7	48	0
Commercial	1,944	567	347	13	213	97	87	26	3
Industrial	617	598	418	241	236	176	45	14	1
Oil Company	19	42	561	29	34	2	6	26	0
Farm	433	1,612	552	221	351	89	254	0	8
Electric Utility	305	134	195	9	151	17	8	36	90
Railroad	500	1,233	686	345	307	114	189	4	0
Marine	490	301	1,033	0	256	62	101	80	13
Military	70	36	9	4	113	89	7	6	11
Construction	511	549	394	150	295	91	194	7	3
Other	159	59	123	30	60	31	22	7	0
Total	10,447	5,760	4,319	1,171	2,153	849	921	254	129

The low-sulfur spillover percentages for the PADDs are calculated by dividing the total spillover volume in each PADD by the respective total potential non-highway demand volume. We use the demand volumes for all non-highway categories for this calculation, in the absence of information indicating that spillover fuel is used differentially in any non-highway end-use categories. This implicitly assumes that each spillover gallon has an equal chance of being sold for use in any non-highway application within each PADD.[A] The resulting low-sulfur spillover fractions for each of the five PADDs are shown in Table 7.1-4.

Table 7.1-4
Highway Diesel Fuel Spillover Percentages by PADD

Diesel Fuel Category	PADD I	PADD II	PADD III	PADD IV	PADD V
Highway Spillover (million gallons)	1,029	1,799	1,303	738	1,250
Potential Off-Highway (million gallons)	10,447	5,760	4,319	1,171	2,153
Spillover (%)	10	31	30	63	58

For PADD 5, it was necessary to develop separate refining regions within PADD 5 for the refinery cost analysis. For this reason, separate spillover percentages were estimated for these separate PADD 5 subregions. This was accomplished by first estimating the spillover percentages of states which are known to have specific spillover characteristics. The State of California already regulates the sulfur content of both the highway and nonroad diesel fuel pools to 500 ppm, thus very little of the diesel fuel is currently unregulated by the State. The tendency is that as more of the fuel pool is regulated, the higher the percentage of spillover into the non-highway diesel fuel pool as the distribution system has little tolerance for small volumes of high sulfur fuels. This was confirmed by talking to a staff member within California's fuel regulatory division of the Air Resources Board. Based on this conversation, California's spillover fraction was estimated to be 100 percent. At the other end of the spectrum, Alaska's highway volume is much smaller than the non-highway volume, thus, very little spillover is expected. Using PADD 1 as a guide, which has about 10 percent spillover and a higher ratio of highway to non-highway diesel fuel, the spillover for Alaska was estimated to be half that of PADD 1, or 5 percent. The spillover for Hawaii and the rest of PADD 5 (Washington, Oregon, Nevada and Arizona) was back-calculated from volumes from these various states, their estimated spillover volumes and the overall spillover percentage of the PADD which is 58 percent. The spillover percent for Hawaii and the rest of PADD 5 was estimated to be 24 percent. The spillover percentages for each of the geographic areas in PADD 5 are shown in Table 7.1-5.

[A] Different national average estimates for spillover by non-highway end use still result due to differences in spillover percentages and fuel volumes among the non-highway applications between the PADDs.

* Different national average estimates for spillover by non-highway end use still result due to differences in spillover percentages and fuel volumes among the non-highway applications between the PADDS.

Table 7.1-5
Highway Diesel Fuel Spillover Percentages for PADD 5 Subregions

	PADD V AZ, NV, OR, WA	PADD V CA	PADD V AK	PADD V HI
Spillover (%)	24	100	5	24

The spillover percentages for PADDs 1-4 and the various subregions for PADD 5 are used in the following sections to estimate the volume of high-sulfur diesel fuel which would be affected by the proposed rules.

7.1.2.2 Land-Based Nonroad Fuel Volumes

As previously mentioned, the primary information source underlying our assessment of nonroad fuel volumes is the *Fuel Oil and Kerosene Sales* Report, published annually by the Energy Information Administration (EIA).[1] The report presents results of a national statistical survey of approximately 4,700 fuel suppliers, including refiners and large companies who sell distillate fuels for end use (rather than resale). The sample design involves classification of fuel suppliers based on sales volume (stratification), with subsamples in individual classes (strata) optimized to improve sample precision. Distillate fuels surveyed that are relevant to this analysis include diesel and heating oils in grades No. 1, No. 2 and No. 4, kerosene and jet fuel. The survey requests respondents to report estimates of fuel sold for eleven “end uses,” that correspond to broad economic sectors, such as “Industrial,” “Construction” and “Farm,” as described below. (See Table 7.1-6).

Before publication, EIA takes measures to quality-assure survey results. Automated and manual procedures serve to identify missing values, potential misreporting, and evaluate “outlier” values. Diesel consumption for the on-highway end use is represented by estimates published annually by the Federal Highway Administration (FHWA).[3] EIA uses the FHWA data because it is their perspective that EIA’s sampling technique gives inadequate coverage of truck stops. Finally, they perform an adjustment or “post-stratification,” to bring total survey results into agreement with total annual supply as reported in the *Petroleum Supply Annual*.[2] For this step, “supply” refers to “product-supplied” to the end-use market, calculated as domestic production plus imports less exports and stock changes, as calculated for each Petroleum Administration for Defense District (PADD). The adjustment is calculated at the PADD level, and applied uniformly to each state and end-use within each PADD.

The EIA FOKS report estimates volumes of distillate sold into end-uses or economic sectors. It does not directly represent fuel consumption, or attempt to determine how fuel is used after it is sold. Thus, sales estimates encompass all potential uses, including on-highway mobile sources, non-road mobile sources, and stationary sources such as heating, cooling, crop drying and power generation. In deriving an estimate of total fuel consumption for nonroad engines, our basic approach is to estimate a fraction of total sales in each end use that represents nonroad fuel consumption. With the exception of the railroad and on-highway end uses, the resulting fractions directly follow guidance from EIA staff.

We derived the nonroad fraction in each end use in two steps. Beginning with total fuel volumes for a given fuel grade or grades, we estimate a proportion representing diesel fuel (as opposed to heating oil), and of the diesel fuel portion, we estimate a second fraction assumed to represent nonroad use. We describe nonroad diesel fuel consumption as estimated for each end use category below.

Farm. For this end use, two fuel grades are reported, “diesel” and “distillate.” We assume that 100% of the diesel represents nonroad use, and 0% of the distillate, which represents other uses, such as heating and crop drying.

Construction/Other Off-Highway(Logging). For the construction and logging/other-non-highway end uses, we assume that 95% of total sales is diesel fuel, and that 100% of the diesel represents nonroad use.

Industrial. This end use is essentially equivalent to the manufacturing sector, and differs from most others in that EIA reports sales for five individual fuel grades, which simplifies estimation of nonroad diesel consumption. At the outset, we assume that sales of No. 2 fuel oil and No. 4 distillate include no diesel fuel. These grades represent other uses in this category, such as space heating, meaning that none of the fuel in these categories represents nonroad use. Conversely, for No. 2 diesel (low and high sulfur), we assume that 100% of sales is diesel fuel, and 100% of the diesel represents nonroad use. For the remaining category, No. 1 distillate, diesel and fuel oil are not distinguished. Following guidance from EIA staff, we have estimated that 40% of No. 1 distillate sales represent diesel fuel, that 100% of this diesel represents nonroad use, and that the remainder represents No. 1 fuel oil used in other applications, such as space heating.

Commercial. This end use is broadly equivalent to the service sector. As with the industrial end use, distillate sales are also reported by fuel grade. However, the commercial and industrial end uses differ in that the commercial category includes sales for on-highway use. Distillate sales for use in motor vehicles include fuel supplied to school-bus and government fleets (local, state and federal). These sales are classified as “commercial” sales because they are exempt from fuel taxes, as is fuel for nonroad use in most jurisdictions. As in the industrial end use, we assume that none of the No. 2 fuel oil or No. 4 distillate represents nonroad use of diesel fuel. In addition, to account for the on-highway fuel consumption in this end use, we assume that none of the low-sulfur No. 2 diesel represents nonroad use. As in industrial, we assign 100% of the high-sulfur No. 2 diesel to nonroad use. After consultation with EIA staff, we have estimated that 40% of the No. 1 distillate is diesel fuel, and that 50% of this diesel represents nonroad use.

For most of the remaining end uses, individual fuel grades are not distinguished, necessitating broader assumptions in estimation of nonroad fuel use.

Oil Company. Sales for this end use include fuel purchased for drilling and refinery operations. We assume that 50% of the reported distillate is diesel fuel, and assign 100% of the diesel to operation of nonroad equipment. We assume that the remainder represents other uses such as underground injection under pressure to fracture rock.

Military. For the military end use, fuel sales are reported for diesel and distillate. We assume that 85% of the diesel represents use in 'non-tactical' nonroad equipment, and that 0% of the distillate represents nonroad use. We exclude some fuel because the NONROAD model does not attempt to represent fuel use or emissions from 'tactical' military equipment, such as tanks and personnel carriers because they are not covered by EPA emission standards.

Railroad. Again, we assume that the vast majority of fuel sales in the railroad end use represents locomotive operation, however, based on guidance from a major railroad, we assume that a small fraction of reported sales represent operation of nonroad equipment used by railroads. Accordingly, we assign 1% of the railroad fuel sales to nonroad use, which corresponds to "Railway Maintenance" equipment as represented in the NONROAD model.

In three of the remaining end uses, *Electric Utility*, *Vessel Bunkering* and *Residential*, we assign no fuel to nonroad use.

On-Highway. As the name implies, this end use represents sales for use in motor vehicles on roads and highways, and is represented in the survey by the volume reported by FHWA.[3] Many organizations own mixed fleets and purchase both highway and non-road diesel, for which reason it is plausible to assume that some fraction of the fuel attributed by FHWA to on-highway use is actually used in nonroad engines. Because owners can legally use undyed low-sulfur diesel in nonroad equipment, convenience or economy may encourage owners who purchase undyed diesel to use it in nonroad equipment. Additionally, some owners might find it expedient or necessary to purchase at least some of their diesel in commercial outlets such as gas stations, where dyed "offroad" diesel is less available.

However, to reassign a fraction of the on-highway fuel to nonroad use, it is not sufficient simply to postulate that low-sulfur undyed diesel is used in nonroad engines. Additional constraints must be met to ensure that the EIA survey has not included the fuel in another end-use, and that FHWA has not accounted for the fuel by subtracting it from the on-highway total. For purposes of this study, we believe that four conditions must apply to justify a presumption that fuel sales assigned to on-highway use would have been used in nonroad engines: (1) The fuel sales were taxed, i.e., sales of undyed "low-sulfur highway diesel," (2) The buyer does not claim a tax credit or refund on the fuel sale(s), (3) The buyer uses the fuel in nonroad equipment, and (4) The EIA survey has not already accounted for the fuel.

The first condition is necessary because FHWA estimates on-highway fuel on the basis of fuel tax receipts reported by the states. In general, sales of undyed diesel are subject to state and federal sales and use taxes; however, the purchaser is eligible for a tax refund or credit in most jurisdictions, if the fuel is used in offroad equipment. To account for this possibility, FHWA subtracts tax refunds from total receipts, which should effectively remove undyed fuel purchased for use in nonroad equipment from the on-highway total. However, it is probable that only a fraction of owners who are eligible actually take advantage of fuel tax refunds or credits, because they are unaware that the option is available or because they find the process inconvenient. Thus, if the purchaser forgoes applying for a refund or credit, FHWA leaves the fuel in the on-highway total (the second condition above), and if the fuel is actually used in nonroad equipment (the third condition above), FHWA also misclassifies it as on-highway consumption.

To reclassify such fuel as nonroad consumption, it is also necessary to be confident that the EIA survey has not effectively assigned it to another end use (the fourth condition above). During quality-assurance, EIA attempts to identify and remove distillate sales intended “primarily for on-highway use” Fractions of such sales used in nonroad engines would thus not be reflected in estimates of distillate sales. Also, fuel purchased at truck stops or gas stations and subsequently used in nonroad equipment would not appear in survey results, because the survey does not attempt to represent sales from these retail outlets.

An example scenario meeting all four conditions stated above would represent sales of undyed diesel at retail outlets, for which the purchaser claims no tax credit or refund, and uses the fuel in nonroad equipment. We assume that such a scenario is not uncommon in the construction or commercial end uses, in which operations can be decentralized, dispersed or remote, and operators numerous and highly mobile, refueling when and where convenient. Such a situation is especially likely for the growing fleet of diesel rental equipment where available refueling sites are likely to be highway service stations and where volumes may not warrant seeking tax refunds.

The Northeast States for Coordinated Air Use Management (NESCAUM) recently conducted a survey of diesel fuel use in construction equipment in New England, under a grant funded by EPA. The survey was designed to develop methods to estimate emission inventories for construction equipment. The study area included two counties, one in Massachusetts and one in Pennsylvania. Equipment owners in selected sectors were targeted, including construction, equipment rental, wholesale trade, and government (local highway departments). Surveyors administered a questionnaire requesting information about fuel purchases and associated tax-credits. Owners reported quantities and proportions of high-sulfur (dyed) and low-sulfur (undyed) diesel fuel purchased over the previous year. Owners who reported purchases of undyed diesel fuel for use in construction equipment were also requested to indicate whether they applied for tax credits for which they would be eligible under state or federal law.

Based on EPA’s analysis of the survey results, approximately 20% of all diesel fuel purchased for use “in construction” was undyed diesel for which the purchaser had not applied for a tax refund. For purposes of deriving a protective estimate, it was assumed that 50% of the un-refunded fuel was purchased at gas stations or truck stops, amounting to 10% of total diesel purchased for use "in construction equipment." In the context of the scenario described above, the implication is that 10% of the total nonroad fuel consumption in the construction and commercial end uses (F_{TOTAL}) is undyed diesel misclassified as on-highway use (F_{FHWA}), or

$$F_{FHWA} = 0.1F_{TOTAL}$$

At the same time, the nonroad fuel consumption in these end uses captured by the FOKS survey (F_{FOKS}) comprises the remaining 90% of the total, or

$$F_{FOKS} = 0.9\,F_{TOTAL}$$

These two relationships allow us to estimate the misclassified diesel fuel in terms of nonroad fuel consumption estimated from the FOKS survey

$$F_{FHWA} = 0.1\left(\frac{F_{FOKS}}{0.9}\right) = \left(\frac{0.1}{0.9}\right)F_{FOKS} = 0.11F_{FOKS}$$

meaning that F_{FHWA} can be estimated as ~$0.1F_{FOKS}$.

We estimated the misclassified highway volume (F_{FHWA}) at the national level and individually for each PADD, using FOKS-derived estimates of nonroad diesel consumption in the construction and commercial end uses for the nation and each PADD, respectively. Summing across the nation, this estimate represents 230 million gallons or approximately 0.7% of the on-highway total.

Table 7.1-6 presents national land-based nonroad fuel consumption for calendar year 2000, by end use. At the national level, the table shows estimates of total sales in each end use, plus fractions representing diesel fuel and nonroad consumption, and resulting fuel volumes representing nonroad consumption.

We derived fuel consumption estimates for each PADD by applying the same distillate and diesel fractions developed above to fuel sales for each PADD. To meet requirements for the economic analysis, the states of California, Hawaii and Alaska are presented individually, with the remaining states in PADD 5 treated as an aggregate. Tables 7.1-7 and 7.1-8 present fuel sales and estimated nonroad fuel consumption for each PADD, with PADD 5 subdivided as described.

Table 7.1-6
Land-Based Nonroad Distillate Use, National Estimates, Calendar Year 2000

End Use	Fuel Grade	Distillate (M gal)	Diesel (%)	Diesel (M gal)	Nonroad (%)	Nonroad (M gal)
Farm	diesel	3,080	100	3,080	100	3,080
	distillate	89	0	0	0	0
Construction	distillate	1,900	95	1,805	100	1,805
Other/(Logging)	distillate	431	95	409	100	409
Industrial	No. 2 fuel oil	357	0	0	0	0
	No. 4 distillate	39	0	0	0	0
	No. 1 distillate	54	40	22	100	22
	No. 2 low-S diesel	810	100	810	100	810
	No. 2 high-S diesel	889	100	889	100	889
Commercial	No. 2 fuel oil	1,576	0	0	0	0
	No. 4 distillate	198	0	0	0	0
	No. 1 distillate	64	40	25	50	13
	No. 2 low-S diesel	1,061	100	1,061	0	0
	No. 2 high-S diesel	475	100	475	100	475
Oil Company	distillate	685	50	342	100	342
Military	diesel	180	100	180	85	153
	distillate	54	0	0	0	0
Electric Utility	distillate	793	100	793	0	0
Railroad	distillate	3,071	95	2,917	1.0	29
Vessel Bunkering	distillate	2,081	90	1,873	0	0
On-Highway	diesel	33,130	100	33,130	0.7	229
Residential	No. 2 fuel oil	6,086	0	0	0	0
	No. 1 distillate	118	0	0	0	0
Total		57,217		47,800		8,254

Table 7.1-7
Distillate Fuel Sales by PADD, Calendar Year 2000 (million gallons)

End Use	Fuel Grade	PADD							
		1	2	3	4	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Farm	diesel	389	1,572	549	219	90	254	0.03	8
	distillate	44	40	3	1	0.08	0	0.001	0
Construction	distillate	511	549	394	150	91	194	7	3
Other/(Logging)	distillate	160	59	123	30	31	22	7	0.04
Industrial	No. 2 fuel oil	219	111	4	8	11	0.3	4	0.05
	No. 4 distillate	33	3	2	2	1	0	0	0
	No. 1 distillate	1	26	3	13	1	0	10	0
	No. 2 low-S diesel	116	176	193	202	79	43	0.02	1
	No. 2 high-S diesel	281	285	218	18	74	2	10	0.6
Commercial	No. 2 fuel oil	1,304	102	141	7	5	3	12	0.05
	No. 4 distillate	197	0.7	0	0	0.02	0	0.02	0
	No. 1 distillate	3	36	0.9	11	3	0.4	10	0
	No. 2 low-S diesel	418	276	146	69	66	79	4	3
	No. 2 high-S diesel	219	153	58	16	15	5	6	3
Oil Company	distillate	19	42	561	29	1	6	26	0.05
Military	diesel	41	15	9	2	87	7	6	11
	distillate	29	21	11	2	2	0	0.05	0
Electric Utility	distillate	304	134	195	8	106	8	36	0.9
Railroad	distillate	500	1,233	686	345	114	189	4	0
Vessel Bunkering	distillate	490	301	1,033	0.2	61	101	80	13
On-Highway	diesel	10,228	11,141	5.644	1,475	1,885	2,633	91	34
Residential	No. 2 fuel oil	5,391	557	1	30	76	7	25	0.009
	No. 1 distillate	8	72	0.1	9	6	0.2	23	0
Total		20,906	16,904	9.976	2,647	2,806	3,553	361	78

Table 7.1-8
Land-Based Nonroad Diesel Consumption for the Nation and by PADD, 2000 (million gallons)

End Use	Fuel Grade	Nation	PADD							
			1	2	3	4	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Farm	diesel	3,080	389	1,572	549	219	89	254	0.03	8
	distillate	0	0	0	0	0	0	0	0	0
Construction	distillate	1,805	485	522	375	143	86	184	6	3
Other/(Logging)	distillate	409	151	56	116	29	30	21	6	0.04
Industrial	No. 2 fuel oil	0	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0	0
	No. 1 distillate	22	0.5	10	1	5	0.5	0	4	0
	No. 2 low-S diesel	810	116	176	193	202	79	43	0.02	1
	No. 2 high-S diesel	889	281	285	218	18	74	2	10	0.6
Commercial	No. 2 fuel oil	0	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0	0
	No. 1 distillate	13	0.5	7	0.2	2	0.5	0.1	2	0
	No. 2 low-S diesel	0	0	0	0	0	0	0	0	0
	No. 2 high-S diesel	475	219	153	58	16	15	5	6	3
Oil Company	distillate	342	10	21	280	15	0.7	3	13	0.02
Military	diesel	153	35	13	8	2	74	6	5	9
	distillate	0	0	0	0	0	0	0	0	0
Electric Utility	distillate	0	0	0	0	0	0	0	0	0
Railroad	distillate	29	5	12	7	3	1	2	0.04	0
On-Highway	diesel	229	71	68	43	16	10	19	1	0.6
Total		8,254	1,762	2,895	1,849	669	461	539	54	26

The high-sulfur diesel fuel volumes are estimated by applying the highway spillover percentages to the results shown in Tables 7.1-4 and 7.1-5. Specifically, the spillover percentage is applied to the volume of diesel fuel remaining after the reclassified highway volume (i.e., highway fuel actually used in nonroad engines) is subtracted from the total land-based nonroad engine volume. This is done because the spillover fraction was developed from the total highway demand before the transfer was made. Table 7.1-9 shows the derivation of the high-sulfur diesel fuel volume for land-based nonroad engines.

Table 7.1-9
Land-Based High-Sulfur Diesel Fuel Demand by PADD, 2000 (million gal)

	PADD							
Diesel Fuel Category	1	2	3	4	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Total Land-Based	1,762	2,895	1,849	669	461	539	54	26
Low-Sulfur Hwy Transfer	71	68	43	16	10	19	1	1
Total Less Hwy Transfer	1,691	2,827	1,806	653	451	520	53	25
Hwy Spillover Percentage (%)	10	31	30	63	24	100	5	24
Land-Based Low Sulfur	168	882	545	410	107	520	3	6
Land-Based High Sulfur	1,523	1,945	1,261	243	344	0	50	19

7.1.2.3 Locomotive Diesel Fuel Demand

The estimates of diesel fuel demand for locomotives are taken from the information presented in Section 7.1.2.2. In summary, the locomotive estimates were developed by taking the railroad distillate fuel values directly from the EIA FOKS report for the geographic areas of interest, and multiplying them by 0.95, which is the fraction of distillate fuel that is assumed to be diesel grade. This results in estimates of the diesel fuel demand for railroads. To find only the volume of diesel fuel used by locomotives, the fraction of diesel fuel that is assumed to be used by rail maintenance (i.e., 0.01) is subtracted from the diesel railroad volumes. The estimates of high-sulfur diesel are determined by applying the highway spillover percentages to the total locomotive fuel volumes.

The locomotive fuel demand estimates for 2000 are shown in Table 7.1-10 for the geographic areas of interest.

Table 7.1-10
Locomotive High-Sulfur Diesel Fuel Demand by PAAD, 2000 (million gallons)

	PADD							
Diesel Fuel Category	1	2	3	4	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Total Locomotive	470	1,160	646	324	107	178	4	0
Hwy Spillover Percentage (%)	10	31	30	63	24	100	5	24
Locomotive Low Sulfur	47	362	195	204	25	178	0	0
Locomotive High Sulfur	423	798	451	120	82	0	4	0

7.1.2.4 Marine Diesel Fuel Demand

The estimates of diesel fuel demand for marine vessels were developed base on guidance from EIA staff. Specifically, the demand volumes are estimated by taking the vessel distillate values directly from the EIA FOKS report and multiplying it by 0.90, which is the fraction of distillate fuel sales that is assumed to represent diesel fuel for that category. The estimates of high-sulfur diesel are determined by applying the highway spillover percentages to the resulting total marine fuel volumes.

The marine fuel demand estimates for 2000 are shown in Table 7.1-11 for the geographic areas of interest.

Table 7.1-11
Marine High-Sulfur Diesel Fuel Demand by PAAD, 2000 (million gallons)

Diesel Fuel Category	PADD							
	1	2	3	4	5 (except CA, HI, AK)	5 CA	5 AK	5 HI
Total Marine	441	271	930	0	55	91	72	12
Hwy Spillover Percentage (%)	10	31	30	63	24	100	5	24
Marine Low Sulfur	47	36,285	281	0	13	91	4	3
Marine High Sulfur	397	7,186	649	0	42	0	68	9

7.1.2.5 Remaining Non-Highway Diesel Fuel Demand

It is also necessary to estimate diesel fuel demand volumes for the remaining non-highway end uses that may use diesel fuel in order to complete the economic analysis. By definition, this category includes any application other than land-based nonroad engines, locomotives, or marine vessels.

The demand for diesel fuel in this broad category is found in three steps. First, the overall volumes of fuel consumed by all non-highway end-uses is determined from the EIA FOKS report. These demand volumes were developed for the geographic areas of interest as presented in Section 7.1.2.1, Table 7.1-3. Second, the demand volumes are adjusted to include the volume of fuel reclassified from the highway vehicle category to the land-based nonroad engine category. These volumes were derived in Section 7.1.2.2, Table 7.1-8. Third, and finally, diesel fuel demands for remaining non-highway end uses are calculated by subtracting the combined volumes for land-based nonroad engines, locomotives, and marine vessel (as previously determined in Sections 7.1.2.2 through 7.1.2.4) from the adjusted diesel demand for all non-highway end uses. The estimates of high-sulfur diesel are then found by applying the highway spillover percentages to these other non-highway demand volumes. The results are shown in Table 7.1-12.

Table 7.1-12
Other Off-Highway High-Sulfur Diesel Fuel Demand by PADD, 2000 (million gallons)

	PADD							
Diesel Fuel Category	1	2	3	4	5 AZ, NV, OR, WA	5 CA	5 AK	5 HI
Potential Off-Highway	10,447	5,760	4,319	1,171	849	921	254	129
Highway Transfer	71	68	43	16	10	19	1	1
Adjusted Off-Highway	10,518	5,828	4,362	1,187	859	940	255	130
Land-Based Nonroad, Locomotive, and Marine	2673	4326	3425	993	623	808	130	38
Other Off-Highway	7,845	1,502	937	194	307	131	141	7
Hwy Spillover Percentage (%)	10	31	30	63	24	100	5	24
Other Off-Highway Low Sulfur	781	469	283	122	73	131	7	2
Other Off-Highway High Sulfur	7,064	1,034	654	72	234	0	134	5

7.1.2.6 Summary of Diesel Fuel Demand for 2000

Table 7.1-13 summarizes the diesel fuel demand estimates for each of the geographic areas of interest for 2000 based on the information in the preceding sections. In this table, the low-sulfur demand volumes for land-based nonroad engines are found by applying the highway spillover percentages to the total volumes for this category minus the reclassified highway gallons. The reclassified highway spillover gallons are then added to these results to produce the total low-sulfur volumes for land-based nonroad engines. Totals for the U.S. and the U.S. minus California are also shown for completeness.

Table 7.1-13
Summary of Diesel Fuel Demand for 2000 (million gallons)

Category	Fuel Type	PADD									
		1	2	3	4	5 AZ, NV, OR, WA	AK	HI	CA	U.S.	U.S. - CA
Revised Highway	total	10,157	11,074	5,601	1,459	1,875	90	33	2,614	32,902	30,288
	high S	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Land-Based Nonroad	total	1,762	2,895	1,849	669	461	54	26	539	8,255	7,716
	low S	239	950	588	426	117	4	7	539	2,871	2,332
	high S	1,523	1,945	1,261	243	344	50	19	0	5,384	5,384
Locomotive	total	470	1,160	646	324	107	4	0	178	2,889	2,711
	low S	47	362	195	204	25	0	0	178	1,011	833
	high S	423	798	451	120	82	4	0	0	1,878	1,878
Marine	total	441	271	930	0	55	72	12	91	1,872	1,781
	low S	44	85	281	0	13	4	3	91	520	429
	high S	397	186	649	0	42	68	9	0	1,352	1,352
Subtotal (NR, Loc, Marine)	total	2,673	4,326	3,425	993	623	130	38	808	13,016	12,208
	low S	330	1,397	1,064	630	155	7	10	808	4,402	3,594
	high S	2,343	2,929	2,361	363	468	123	28	0	8,614	8,614
Other Non-Highway	total	7,845	1,502	937	194	307	141	7	131	11,065	10,934
	low S	781	469	283	122	73	7	2	131	1,868	1,737
	high S	7,064	1,034	654	72	234	134	5	0	9,197	9,197
TOTAL	total	20,675	16,902	9,963	2,646	2,805	361	78	3,553	56,983	53,430
	low S	11,269	12,939	6,948	2,211	2,103	105	44	3,553	39,171	35,618
	high S	9,406	3,963	3,015	435	702	257	34	0	17,812	17,812

7.1.3 Diesel Fuel Demand by PADD for 2008

Diesel fuel demand in 2008 is projected for each end use category by applying various growth factors to the 2000 diesel fuel demand volumes shown in Table 7.1-13. This section shows how the growth factors were determined and applied to each end-use category. Finally, the low-sulfur diesel fuel estimates for 2008 are divided into separate volumes of 15 ppm and 500 ppm sulfur concentrations (i.e., highway diesel fuel) in order to facilitate the air quality analysis.

7.1.3.1 2000-2008 Growth Factors

The growth factors for highway diesel fuel, locomotives, and other non-highway end uses were developed from the *Annual Energy Outlook 2002* (AEO2002) report, which is published by the Energy Information Administration.[4] The growth factor for land-based nonroad engines was taken from estimates of diesel fuel consumption from the draft NONROAD2002 model. The factor for marine diesel fuel was developed from information contained in the 1999 Final Regulatory Impact Analysis for the Marine Diesel Emission Standards, which was published by EPA.[5] Each of the growth factors and their respective sources are shown in Table 7.1-14. The derivation of the composite growth factor that was used for the other non-highway end use category is shown in Table 7.1-15.

Table 7.1-14
2000-2008 Growth Factors by End-Use Category

End Use	2000-2008 Multiplicative Growth Factor	% Simple Annual Growth Rate	Source/Comments
Highway	1.238	2.98	AEO2002, Table 7, Energy Use by Mode, Freight Trucks (over 10,000 lbs. GVWR)
Land-Based Nonroad	1.229	2.87	Calculated from 2000 and 2008 Draft NONROAD2002 Model diesel fuel consumption outputs.
Locomotive	1.083	1.04	AEO 2002, Table 7, Energy Use by Mode, Railroad
Marine	1.090	1.13	Calculated from 2000 and 2008 CO emissions inventories (as a surrogate for fuel consumption) as reported in the Final Regulatory Impact Analysis, Control of Emissions for Marine Diesel Engines, 1999.
Other Non-Highway	1.074	0.93	See Table 7.1-15. Primarily diesel fuel and heating oil.

Table 7.1-15
2000-2008 Composite Growth Factor for Other Non-Highway End-Uses

End Use	Energy Consumption (Quadrillion BTU)	Fraction of Total	2000-2008 Multiplicative Growth Factor	Consumption Weighted Multiplicative Growth Factor	Source of Energy Consumption
Commercial	0.42	0.174	1.105	0.192	AEO2002, Table 2, Commercial, Distillate Fuel
Industrial	1.18	0.489	1.063	0.520	AEO2002, Table 2, Industrial, Distillate Fuel
Farm	0.528	0.219	1.039	0.227	AEO2002, Table 32, Agriculture, Distillate Fuel
Construction	0.285	0.118	1.138	0.134	AEO2002, Table 32, Construction, Distillate Fuel
Composite Average[a]				1.074	

[a] Growth in the residential heating oil end-use category was inadvertently excluded from the composite growth factor of the other non-highway category. This will be added for the final rulemaking.

The 2000-2008 average annual growth rate of 2.87 percent for land-based nonroad engines, presented in Table 7.1-14 above, is identical to that used in Chapter 3 for these engines. This compares with an annual growth rate of 0.97 percent that was developed using data from AEO2002 (See Appendix 7B.) The growth rates for locomotives and marine shown in Table 7.1-14 are the same as the values used in Chapter 3 for these engines.

7.1.3.2 Division of Low-Sulfur Diesel Fuel into 15 ppm and 500 ppm Volumes

As previously noted, the highway diesel fuel spillover volume is divided into 15 ppm and 500 ppm sulfur levels to facilitate the air quality analysis. The 15 ppm sulfur pool is projected to comprise 74 percent of the spillover volume, while 500 ppm sulfur pool is projected to comprise 26 percent of the spillover volume. The value is 74 percent 15 ppm diesel fuel because although 80 percent of each PADDs highway diesel fuel must be 15 ppm in 2006, highway diesel fuel produced by small refineries is allowed to be exempt from having to comply in 2006, and they comprise 5 percent of the national highway diesel fuel production volume. Then, the 75/25 relative volumes were adjusted to account for downgrading in the distribution system thus resulting in the 74 and 26 percent values. When this volume methodology was created, the highway plans for most of the small refiners were not known, so it was assumed that all of them would take the delay option. However, we now know that some are taking the gasoline for diesel fuel option which requires them to comply with the highway diesel fuel option in 2006, in return for a three year delay with the Tier 2 gasoline sulfur standard. These small refineries will therefore comply with the Highway Program sulfur requirements in 2006 and will make the percentage of highway diesel fuel complying to the 15 ppm cap standard in 2006 closer to 80 percent. This will be updated for the final rulemaking.

7.1.3.3 Summary of Diesel Fuel Demand for 2008

The diesel fuel demand estimates for 2008 are shown in Table 7.1-16.

Table 7.1-16
Summary of Diesel Fuel Demand by PADD for 2008 (million gallons)

Category	Fuel Type	PADD 1	2	3	4	5 AZ, NV, OR, WA	AK	HI	U.S. - CA	CA	U.S.
Revised Highway	total	12,575	13,710	6,934	1,806	2,321	111	41	37,499	3,236	40,735
	15 ppm diesel	9,324	10,165	5,141	1,339	1,721	83	30	27,804	3,236	31,040
	500 ppm diesel	3,251	3,544	1,793	467	600	29	11	9,695	0	9,695
	high S	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Land-Based Nonroad	total	2,166	3,559	2,273	822	567	66	32	9,486	663	10,149
	15 ppm diesel	219	866	536	389	106	3	6	2,125	662	2,788
	500 ppm diesel	77	302	187	135	37	1	2	741	0	741
	high S	1,872	2,391	1,550	298	423	62	23	6,620	0	6,620
Locomotive	total	509	1,256	700	351	116	4	0	2,936	193	3,129
	15 ppm diesel	38	291	157	163	20	0	0	669	193	862
	500 ppm diesel	13	101	55	57	7	0	0	233	0	233
	high S	458	864	488	130	88	4	0	2,034	0	2,034
Marine	total	481	295	1,014	0	60	78	13	1,941	99	2,040
	15 ppm diesel	35	68	227	0	11	3	2	347	99	446
	500 ppm diesel	12	24	79	0	4	1	1	121	0	121
	high S	433	203	708	0	46	75	10	1,474	0	1,474
Subtotal (NR, Loc, Marine)	total	3,156	5,111	3,987	1,173	743	149	45	14,364	955	15,318
	15 ppm diesel	291	1,225	920	552	137	6	9	3,141	955	4,096
	500 ppm diesel	102	427	321	193	48	2	3	1,095	0	1,095
	high S	2,763	3,458	2,746	429	557	141	33	10,127	0	10,127
Other Off-Highway	total	8,425	1,614	1,007	209	330	151	8	11,743	141	11,884
	15 ppm diesel	622	373	225	97	58	6	1	1,383	141	1,524
	500 ppm diesel	217	130	79	34	20	2	0	482	0	482
	high S	7,586	1,110	703	78	252	144	6	9,878	0	9,878
TOTAL	total	24,157	20,434	11,927	3,188	3,394	412	93	63,605	4,332	67,937
	15 ppm diesel	10,238	11,764	6,287	1,988	1,917	95	40	32,328	4,332	36,660
	500 ppm diesel	3,570	4,102	2,192	693	669	33	14	11,272	0	11,272
	high S	10,349	4,569	3,448	506	809	284	39	20,005	0	20,005

7.1.4. Annual Diesel Fuel Demand (2000-2040) and Associated In-Use Sulfur Levels

The annual diesel fuel volumes and respective in-use sulfur concentrations for land-based nonroad engines, locomotives, and marine vessels are estimated in this section. The estimates of in-use diesel fuel sulfur levels are used in emissions inventory analysis. The diesel volumes are used in the economic analysis. Some of these volume estimates are also used in the emissions inventory analysis described in Chapter 3.

This section begins with a description of the methodology that is used to estimate the diesel demand volumes for 2000-2040. Then the basic inputs for determining the in-use sulfur concentration is discussed. Finally, the volumes and corresponding in-use sulfur levels for each year are presented.

7.1.4.1 Annual Diesel Demand Volume Estimates

Diesel fuel volume estimates by year and by geographic area (nationwide, 49-state without California, and 48-state without Alaska or Hawaii) and corresponding average sulfur levels by year were calculated from the 2008 fuel use estimates presented in Section 7.1.3. The resulting volumes and sulfur levels are presented below in Section 7.1.4.3. The demand estimates for each of the other years were determined by extrapolating the 2008 values according to the nationwide growth rates shown in Table 7.1-17 for land-based nonroad model equipment categories, locomotives, and marine (commercial and recreational). The sources for these growth rates are the same as described earlier in Table 7.1-14.

Although the growth rates in the two tables are consistent, they are not directly comparable. The values in Table 7.1-14 are expressed as simple annual growth (i.e., the percentage change from 2000-2008 divided by the number of years, in this case eight years). The values in Table 7.1-17 are expressed as a percentage change from the previous year, or year-to-year change.

Table 7.1-17
Nationwide Annual Growth Rates for Nonroad Diesel Fuel Use

Year	Nonroad	Locomotive	Marine
2000	—	—	—
2001	2.88	5.15	1.08
2002	2.80	-1.63	1.08
2003	2.72	1.74	1.08
2004	2.65	1.38	1.09
2005	2.58	1.38	1.09
2006	2.50	0.97	1.09
2007	2.44	0.97	1.10
2008	2.38	0.44	1.10
2009	2.32	0.69	1.10
2010	2.27	0.72	1.11
2011	2.23	1.70	1.11
2012	2.18	0.45	1.11
2013	2.14	0.27	1.12
2014	2.09	0.28	1.12
2015	2.05	0.45	1.12
2016	1.99	1.02	1.13
2017	1.95	0.57	1.13
2018	1.91	0.52	1.13
2019	1.88	0.56	1.14
2020	1.84	0.33	1.14
2021	1.81	0.89	1.15
2022	1.78	0.89	1.15
2023	1.75	0.89	1.16
2024	1.72	0.89	1.16
2025	1.69	0.89	1.16
2026	1.65	0.89	1.17
2027	1.62	0.89	1.17
2028	1.60	0.89	1.18
2029	1.57	0.89	1.18
2030	1.55	0.89	1.19
2031	1.52	0.89	1.19
2032	1.50	0.89	1.20
2033	1.48	0.89	1.20
2034	1.46	0.89	1.21
2035	1.44	0.89	1.21
2036	1.41	0.89	1.22
2037	1.40	0.89	1.23
2038	1.38	0.89	1.23
2039	1.36	0.89	1.24
2040	1.34	0.89	1.24

7.1.4.2 In-Use Diesel Sulfur Concentrations

Table 7.1-18 shows the diesel sulfur levels that were used in generating the national in-use average sulfur levels by year that are shown in Section 7.1.4.3.

Table 7.1-18
Factors Used to Calculate In-use Sulfur Levels

Parameter	Value
Average in-use sulfur level for fuel intended to be used in nonroad engines, prior to sulfur control	3400 ppm
Average in-use fuel sulfur level for any fuel designed to meet a standard of 500 ppm	340 ppm
Average in-use fuel sulfur level for fuel designed to meet California's diesel fuel specifications	120 ppm
Average in-use fuel sulfur level for any fuel designed to meet a standard of 15 ppm	11 ppm
Nonroad spillover: Percentage of fuel consumed by nonroad engines that is actually produced to meet highway fuel sulfur standards	34.9%
Locomotive and marine spillover: Percentage of fuel consumed by locomotives and marine vessels that is actually produced to meet highway fuel sulfur standards	32.4%

Each of the sulfur levels and spillover assumptions is further described below.

High-Sulfur Diesel Fuel. The national average in-use sulfur level of uncontrolled nonroad, locomotive, and marine diesel fuel is approximately 3400 ppm. This estimate is derived from 1996 through 2001 fuel survey data reported by the National Institute for Petroleum and Energy Research (NIPER) and TRW Petroleum Technologies (TRW).[6,7] These annual reports provide measured sulfur concentrations and respective fuel volumes for multiple samples in several geographic regions of the country. The information was used to estimate the national average in-use sulfur level as follows. First, the geographic regions were assigned to each of the five PADDs. Second, individual annual average sulfur levels in each PADD were calculated by weighting the respective sulfur content of each sample by its fuel volume (i.e., volume weighting). Third, an overall average sulfur level for each PADD was found by volume weighting the individual annual average sulfur concentrations. Fourth, the national average sulfur level was determined by volume weighting each PADD's overall average sulfur concentration. The final results of this analysis are shown in Table 7.1-19. The details of the method are provided in a memo to the Docket entitled, "Derivation of the National Average In-use Sulfur Level of Uncontrolled Nonroad, Locomotive, and Marine Diesel Fuel".

Table 7.1-19
In-Use Sulfur Concentrations for High-Sulfur Diesel Fuel

PADD	Year	Volume (million gallons)	Sulfur
1	1996	7,637,500	3,423
	1997	6,000,000	2,663
	1998	4,637,500	3,998
	1999	4,275,000	3,474
	2000	9,025,000	3,653
	2001	4,937,500	3,055
	Average	36,512,500	3,384
2	1996	2,825,000	3,600
	1997	2,775,000	2,740
	1998	1,275,000	1,818
	1999	2,912,500	1,717
	2000	10,412,500	2,939
	2001	5,212,500	3,936
	Average	25,412,500	2,999
3	1996	3,137,500	4,539
	1997	3,637,500	3,945
	1998	3,137,500	5,004
	1999	4,637,500	4,177
	2000	3,887,500	4,361
	2001	1,775,000	4,298
	Average	20,212,500	4,366
4	1996	412,500	4,100
	1997	275,000	1,000
	1998	275,000	3,400
	1999	275,000	2,000
	2000	275,000	2,600
	2001	275,000	2,340
	Average	1,787,500	2,691
5	1996	1,912,500	3,002
	1997	3,550,000	2,268
	1998	1,550,000	3,077
	1999	1,550,000	2,065
	2000	--	--
	2001	--	--
	Average	8,562,500	2,541
U.S.	1996	15,925,000	3,641
	1997	16,237,500	2,849
	1998	10,875,000	3,886
	1999	13,650,000	3,148
	2000	23,600,000	3,442
	2001	12,200,000	3,596

1	1996	7,637,500	3,423
	1997	6,000,000	2,663
	1998	4,637,500	3,998
	1999	4,275,000	3,474
	2000	9,025,000	3,653
	2001	4,937,500	3,055
	Average	36,512,500	3,384
2	1996	2,825,000	3,600
	1997	2,775,000	2,740
	1998	1,275,000	1,818
	1999	2,912,500	1,717
	2000	10,412,500	2,939
	2001	5,212,500	3,936
	Average	25,412,500	2,999
3	1996	3,137,500	4,539
	1997	3,637,500	3,945
	1998	3,137,500	5,004
	1999	4,637,500	4,177
	2000	3,887,500	4,361
	2001	1,775,000	4,298
	Average	20,212,500	4,366
4	1996	412,500	4,100
	1997	275,000	1,000
	1998	275,000	3,400
	1999	275,000	2,000
	2000	275,000	2,600
	2001	275,000	2,340
	Average	1,787,500	2,691
5	1996	1,912,500	3,002
	1997	3,550,000	2,268
	1998	1,550,000	3,077
	1999	1,550,000	2,065
	Average	92,487,500	3,401

500 ppm Low-Sulfur Diesel Fuel. The in-use sulfur level of diesel fuel meeting a 500 ppm sulfur standard is 340 ppm. This in-use level, which is based on fuel survey data from NIPER, the American Automobile Manufacturers Association (AAMA), and the American Petroleum Institute (API) / National Petrochemical and Refiners Association (NPRA), is documented in the Final Regulatory Impact Analysis for the emission standards and diesel fuel sulfur requirements affecting 2007 and later heavy-duty highway engines and vehicles.[8]

California 500 ppm Low-Sulfur Diesel Fuel. The in-use sulfur level of diesel fuel meeting a 500 ppm sulfur standard in California is 120 ppm. A level of 140 ppm was previously estimated in the Final Regulatory Impact Analysis for the emission standards and diesel fuel sulfur requirements affecting 2007 and later heavy-duty highway engines and vehicles.[8] However, more recent in-use survey data shows a constantly decreasing sulfur level in California under this standard. Therefore, it is estimated that California will experience an in-use sulfur level of 120 ppm for diesel fuel complying with the 500 ppm sulfur standard in that state.

11 ppm Low-Sulfur Diesel Fuel. It is estimated that refiners will produce diesel fuel with approximately 7-8 ppm sulfur in order for all parties downstream of the refinery gate to meet the 15 ppm sulfur standard. The actual in-use level likely will be somewhere between 7 and 15 ppm. In complex distribution segments, diesel fuel could have a sulfur level close to the 15 ppm sulfur cap due to contamination that occurs throughout the distribution system. On the other hand, simple distribution segments should not experience as much contamination and the resulting sulfur level should not be as high. On average we expect the in-use sulfur level to be approximately 10 ppm. For emissions inventory modeling purposes, 1 ppm sulfur is added to the in-use fuel sulfur level to account for the combustion of lubricating oil in non-highway engines. Therefore, an 11 ppm total sulfur concentration is used to evaluate the effects on emissions of a fuel complying with a 15 ppm sulfur standard.

Spillover Percentages. The average spillover percentages for the land-based nonroad engines and separately for locomotives and marine vessels are calculated by summing the spillover volume for all the PADDs and dividing by the total volume of either land-based nonroad or locomotives and marine volume for all the PADDs. This approach yields slightly different spillover percentages for 50-state and 48-state cases, so as a simplifying assumption in this analysis, the average of these two spillover percentages was used in both cases.

The estimated average in-use sulfur levels of the highway spillover diesel fuel are estimated by applying the sulfur factors shown in Table 7.1-18 to the phase-in schedule for the highway fuel sulfur standards, which were promulgated in 2001 [66 FR 5002]. The results are described in Table 7.1-20.

Estimating the average in-use sulfur levels of non-highway diesel fuel also involves three transitions when fuel sulfur levels are moving from uncontrolled to a proposed standard, or from one proposed control level to the next. The sulfur levels for these transitions are calculated using the information from Table 7.1-21 with the assumption that any fuel transition occurs in June of the calendar year in which the new standard takes effect. Table 7.1-21 displays the resulting transitional year non-highway fuel sulfur levels.

The information described above is used in the next section to calculate the resulting annual in-use sulfur levels for each.

Table 7.1-20
Average Sulfur Level for On-highway Fuel

Year	Average sulfur (ppm)	Explanation
2005 and earlier	340	Nationwide average, excluding California, prior to introduction of 15ppm standard. This is used in the 48-state and 50-state analyses.
2005 and earlier	300	Nationwide average, including California, prior to introduction of 15ppm standard. Assumes 10% of nationwide highway diesel meets California's requirements. This is used in the 49-state analysis.
2006	165	15ppm standard applies beginning in June. Only 80% of the pool meets the 15ppm standard.
2007	69	Only 80% of the pool meets the 15ppm standard.
2008	69	Only 80% of the pool meets the 15ppm standard.
2009	69	Only 80% of the pool meets the 15ppm standard.
2010 and later	11	100% of the pool meets the 15ppm standard

Table 7.1-21
Average Sulfur Levels for Off-highway Fuel Sulfur Standard Transitions (ppm)

	Uncontrolled to 500ppm standard	500ppm standard to 15ppm standard	Uncontrolled to 15ppm standard
Prior to transition year	3400	340	3400
Transition year	1615	148	1423
After transition year	340	11	11

7.1.4.3 Summary of Annual Diesel Fuel Demand and Sulfur Levels

Tables 7.1-22 through 30 present the diesel demand volumes and average in-use sulfur levels for each year, end use category, and area of interest (50-state, 49-state without California, and 48-state without Alaska or Hawaii). The demand volumes are determined by applying the growth rates from Table 7.1-17 to the 2008 demand volumes shown in Table 7.1-16. The average in-use sulfur concentrations are found by combining the average sulfur levels for highway fuel shown in Table 7.1-20 with the average sulfur levels for non-highway fuel from Table 7.1-21. The spillover fractions given in Table 7.1-18 are used to properly weight the highway and non-highway sulfur levels.

The column headings in the subsequent tables are defined as follows. "Affected Volume" refers to the fuel produced to meet applicable nonroad fuel sulfur requirements. The term

"Spillover" refers to fuel produced to meet highway sulfur requirements, but which ends up being used in nonroad equipment. The final columns labeled "Combo S ppm" show the fuel volume-weighted average sulfur levels for the combination of the "Affected Volume" and the "Spillover Volume." The final “Combo S ppm” columns are the sulfur levels that were used for the 50-state and 48-state emissions inventory modeling. Separate 49-state (without California) emissions modeling was not conducted. Note that the 50-state and 48-state Base and Control combination sulfur levels have been set to the average of the 50 & 48-state values, since the difference was negligible. Similarly, the Locomotive and Marine combination sulfur levels have been set to their average to simplify the analysis.

Table 7.1-22
50-State Nonroad Land-based Diesel Fuel Volumes and Sulfur Content

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[a]	Control Combo S ppm[a]
2000	8,255	5,384	3400	3400	2,871	300	2318	2318
2001	8,492	5,539	3400	3400	2,953	300	2318	2318
2002	8,730	5,694	3400	3400	3,036	300	2318	2318
2003	8,967	5,849	3400	3400	3,118	300	2318	2318
2004	9,204	6,004	3400	3400	3,201	300	2318	2318
2005	9,442	6,158	3400	3400	3,283	300	2318	2318
2006	9,678	6,312	3400	3400	3,365	165	2271	2271
2007	9,913	6,466	3400	1615	3,447	69	2237	1075
2008	10,149	6,620	3400	340	3,529	69	2237	245
2009	10,385	6,773	3400	340	3,611	69	2237	245
2010	10,620	6,927	3400	148	3,693	11	2217	100
2011	10,857	7,082	3400	11	3,776	11	2217	11
2012	11,094	7,236	3400	11	3,858	11	2217	11
2013	11,331	7,391	3400	11	3,940	11	2217	11
2014	11,568	7,545	3400	11	4,023	11	2217	11
2015	11,805	7,700	3400	11	4,105	11	2217	11
2016	12,040	7,853	3400	11	4,187	11	2217	11
2017	12,275	8,006	3400	11	4,269	11	2217	11
2018	12,509	8,159	3400	11	4,350	11	2217	11
2019	12,744	8,312	3400	11	4,432	11	2217	11
2020	12,979	8,465	3400	11	4,513	11	2217	11
2021	13,214	8,619	3400	11	4,595	11	2217	11
2022	13,448	8,772	3400	11	4,677	11	2217	11
2023	13,683	8,925	3400	11	4,758	11	2217	11
2024	13,918	9,078	3400	11	4,840	11	2217	11
2025	14,153	9,231	3400	11	4,922	11	2217	11
2026	14,386	9,383	3400	11	5,003	11	2217	11
2027	14,619	9,535	3400	11	5,084	11	2217	11
2028	14,852	9,687	3400	11	5,165	11	2217	11
2029	15,085	9,839	3400	11	5,246	11	2217	11
2030	15,319	9,992	3400	11	5,327	11	2217	11
2031	15,552	10,144	3400	11	5,408	11	2217	11
2032	15,785	10,296	3400	11	5,489	11	2217	11
2033	16,018	10,448	3400	11	5,570	11	2217	11
2034	16,252	10,600	3400	11	5,652	11	2217	11
2035	16,485	10,752	3400	11	5,733	11	2217	11
2036	16,718	10,904	3400	11	5,814	11	2217	11
2037	16,951	11,056	3400	11	5,895	11	2217	11
2038	17,185	11,209	3400	11	5,976	11	2217	11
2039	17,418	11,361	3400	11	6,057	11	2217	11
2040	17,651	11,513	3400	11	6,138	11	2217	11

[a] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 & 48-state values, since the difference was negligible.

Table 7.1-23
50-State Locomotive Diesel Fuel Volumes and Sulfur Content

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[a]	Control Combo S ppm[a]
2000	2825	1836	3400	3400	989	299	2396	2396
2001	2,970	1931	3400	3400	1,040	299	2396	2396
2002	2,922	1,899	3400	3400	1,023	299	2396	2396
2003	2,973	1,932	3400	3400	1,040	299	2396	2396
2004	3,014	1,959	3400	3400	1,055	299	2396	2396
2005	3,055	1,986	3400	3400	1,069	299	2396	2396
2006	3,085	2,005	3400	3400	1,080	165	2352	2352
2007	3,115	2,025	3400	1615	1,090	69	2321	1114
2008	3,129	2,034	3400	340	1,095	69	2321	252
2009	3,150	2,048	3400	340	1,102	69	2321	252
2010	3,173	2,063	3400	340	1,110	11	2302	233
2011	3,227	2,098	3400	340	1,129	11	2302	233
2012	3,242	2,107	3400	340	1,134	11	2302	233
2013	3,251	2,113	3400	340	1,138	11	2302	233
2014	3,260	2,119	3400	340	1,141	11	2302	233
2015	3,274	2,128	3400	340	1,146	11	2302	233
2016	3,308	2,150	3400	340	1,158	11	2302	233
2017	3,327	2,163	3400	340	1,164	11	2302	233
2018	3,344	2,174	3400	340	1,170	11	2302	233
2019	3,363	2,186	3400	340	1,177	11	2302	233
2020	3,374	2,193	3400	340	1,181	11	2302	233
2021	3,404	2,213	3400	340	1,191	11	2302	233
2022	3,434	2,233	3400	340	1,202	11	2302	233
2023	3,465	2,252	3400	340	1,213	11	2302	233
2024	3,496	2,273	3400	340	1,223	11	2302	233
2025	3,527	2,293	3400	340	1,234	11	2302	233
2026	3,559	2,313	3400	340	1,245	11	2302	233
2027	3,590	2,334	3400	340	1,256	11	2302	233
2028	3,622	2,355	3400	340	1,268	11	2302	233
2029	3,655	2,376	3400	340	1,279	11	2302	233
2030	3,687	2,397	3400	340	1,290	11	2302	233
2031	3,720	2,418	3400	340	1,302	11	2302	233
2032	3,753	2,440	3400	340	1,314	11	2302	233
2033	3,787	2,462	3400	340	1,325	11	2302	233
2034	3,821	2,484	3400	340	1,337	11	2302	233
2035	3,855	2,506	3400	340	1,349	11	2302	233
2036	3,889	2,528	3400	340	1,361	11	2302	233
2037	3,924	2,551	3400	340	1,373	11	2302	233
2038	3,959	2,573	3400	340	1,385	11	2302	233
2039	3,994	2,596	3400	340	1,398	11	2302	233
2040	4030	2,620	3400	340	1,410	11	2302	233

[a] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 & 48-state values, since the difference was negligible. Similarly, the Locomotive and Marine combination sulfur levels have been set to their average to simplify the analysis.

Table 7.1-24
50-State Marine Diesel Fuel Volumes and Sulfur Content

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[a]	Control Combo S ppm[a]
2000	1870	1,350	3400	3400	519	299	2396	2396
2001	1,890	1,365	3400	3400	525	299	2396	2396
2002	1,911	1,380	3400	3400	530	299	2396	2396
2003	1,931	1,395	3400	3400	536	299	2396	2396
2004	1,953	1,410	3400	3400	542	299	2396	2396
2005	1,974	1,426	3400	3400	548	299	2396	2396
2006	1,996	1,442	3400	3400	554	165	2352	2352
2007	2,018	1,458	3400	1615	560	69	2321	1114
2008	2,040	1,474	3400	340	567	69	2321	252
2009	2,063	1,490	3400	340	573	69	2321	252
2010	2,086	1,507	3400	340	579	11	2302	233
2011	2,109	1,523	3400	340	586	11	2302	233
2012	2,132	1,540	3400	340	592	11	2302	233
2013	2,156	1,557	3400	340	599	11	2302	233
2014	2,180	1,575	3400	340	605	11	2302	233
2015	2,205	1,593	3400	340	612	11	2302	233
2016	2,230	1,610	3400	340	619	11	2302	233
2017	2,255	1,629	3400	340	626	11	2302	233
2018	2,280	1,647	3400	340	633	11	2302	233
2019	2,306	1,666	3400	340	640	11	2302	233
2020	2,333	1,685	3400	340	648	11	2302	233
2021	2,359	1,704	3400	340	655	11	2302	233
2022	2,387	1,724	3400	340	663	11	2302	233
2023	2,414	1,744	3400	340	670	11	2302	233
2024	2,442	1,764	3400	340	678	11	2302	233
2025	2,471	1,785	3400	340	686	11	2302	233
2026	2,499	1,805	3400	340	694	11	2302	233
2027	2,529	1,827	3400	340	702	11	2302	233
2028	2,559	1,848	3400	340	710	11	2302	233
2029	2,589	1,870	3400	340	719	11	2302	233
2030	2,620	1,892	3400	340	727	11	2302	233
2031	2,651	1,915	3400	340	736	11	2302	233
2032	2,683	1,938	3400	340	745	11	2302	233
2033	2,715	1,961	3400	340	754	11	2302	233
2034	2,748	1,985	3400	340	763	11	2302	233
2035	2,781	2,009	3400	340	772	11	2302	233
2036	2,815	2,033	3400	340	782	11	2302	233
2037	2,850	2,058	3400	340	791	11	2302	233
2038	2,885	2,084	3400	340	801	11	2302	233
2039	2,920	2,110	3400	340	811	11	2302	233
2040	2,957	2136	3400	340	821	11	2302	233

[a] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 & 48-state values, since the difference was negligible. Similarly, the Locomotive and Marine combination sulfur levels have been set to their average to simplify the analysis.

Table 7.1-25
49-State Nonroad Land-based Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm	Control Combo S ppm
2000	7716	5,384	3400	3400	2,332	340	2475	2475
2001	7938	5,539	3400	3400	2,399	340	2475	2475
2002	8,160	5,694	3400	3400	2,466	340	2475	2475
2003	8,382	5,849	3400	3400	2,533	340	2475	2475
2004	8,603	6,004	3400	3400	2,600	340	2475	2475
2005	8,825	6,158	3400	3400	2,667	340	2475	2475
2006	9,046	6,312	3400	3400	2,734	186	2429	2429
2007	9,266	6,466	3400	1615	2,800	77	2396	1150
2008	9,486	6,620	3400	340	2,867	77	2396	260
2009	9,707	6,773	3400	340	2,933	77	2396	260
2010	9,927	6,927	3400	148	3,000	11	2376	107
2011	10,149	7,082	3400	11	3,067	11	2376	11
2012	10,370	7,236	3400	11	3,134	11	2376	11
2013	10,591	7,391	3400	11	3,201	11	2376	11
2014	10,813	7,545	3400	11	3,268	11	2376	11
2015	11,034	7,700	3400	11	3,334	11	2376	11
2016	11,254	7,853	3400	11	3,401	11	2376	11
2017	11,473	8,006	3400	11	3,467	11	2376	11
2018	11,693	8,159	3400	11	3,533	11	2376	11
2019	11,912	8,312	3400	11	3,600	11	2376	11
2020	12,131	8,465	3400	11	3,666	11	2376	11
2021	12,351	8,619	3400	11	3,732	11	2376	11
2022	12,570	8,772	3400	11	3,799	11	2376	11
2023	12,790	8,925	3400	11	3,865	11	2376	11
2024	13,009	9,078	3400	11	3,931	11	2376	11
2025	13,228	9,231	3400	11	3,998	11	2376	11
2026	13,446	9,383	3400	11	4,063	11	2376	11
2027	13,664	9,535	3400	11	4,129	11	2376	11
2028	13,882	9,687	3400	11	4,195	11	2376	11
2029	14,100	9,839	3400	11	4,261	11	2376	11
2030	14,318	9,992	3400	11	4,327	11	2376	11
2031	14,536	10,144	3400	11	4,393	11	2376	11
2032	14,754	10,296	3400	11	4,459	11	2376	11
2033	14,972	10,448	3400	11	4525	11	2376	11
2034	15,190	10,600	3400	11	4,590	11	2376	11
2035	15,408	10,752	3400	11	4,656	11	2376	11
2036	15,626	10,904	3400	11	4,722	11	2376	11
2037	15,844	11,056	3400	11	4,788	11	2376	11
2038	16,062	11,209	3400	11	4,854	11	2376	11
2039	16,280	11,361	3400	11	4,920	11	2376	11
2040	16,498	11,513	3400	11	4,986	11	2376	11

[a] 49-state analysis includes all states except California.

Table 7.1-26
49-State Locomotive Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm	Control Combo S ppm
2000	2651	1,836	3400	3400	815	340	2460	2460
2001	2,787	1,931	3400	3400	856	340	2460	2460
2002	2,742	1,899	3400	3400	842	340	2460	2460
2003	2,790	1,932	3400	3400	857	340	2460	2460
2004	2,828	1,959	3400	3400	869	340	2460	2460
2005	2,867	1,986	3400	3400	881	340	2460	2460
2006	2,895	2,005	3400	3400	889	186	2413	2413
2007	2,923	2,025	3400	1615	898	77	2379	1142
2008	2,936	2,034	3400	340	902	77	2379	259
2009	2,956	2,048	3400	340	908	77	2379	259
2010	2,977	2,063	3400	340	915	11	2359	239
2011	3,028	2,098	3400	340	930	11	2359	239
2012	3,042	2,107	3400	340	935	11	2359	239
2013	3,050	2,113	3400	340	937	11	2359	239
2014	3,059	2,119	3400	340	940	11	2359	239
2015	3,073	2,128	3400	340	944	11	2359	239
2016	3,104	2,150	3400	340	954	11	2359	239
2017	3,122	2,163	3400	340	959	11	2359	239
2018	3,138	2,174	3400	340	964	11	2359	239
2019	3,156	2,186	3400	340	970	11	2359	239
2020	3,166	2,193	3400	340	973	11	2359	239
2021	3,194	2,213	3400	340	982	11	2359	239
2022	3,223	2,233	3400	340	990	11	2359	239
2023	3,252	2,252	3400	340	999	11	2359	239
2024	3,281	2,273	3400	340	1,008	11	2359	239
2025	3,310	2,293	3400	340	1,017	11	2359	239
2026	3,339	2,313	3400	340	1,026	11	2359	239
2027	3,369	2,334	3400	340	1,035	11	2359	239
2028	3,399	2,355	3400	340	1,044	11	2359	239
2029	3,430	2,376	3400	340	1,054	11	2359	239
2030	3,460	2,397	3400	340	1,063	11	2359	239
2031	3,491	2,418	3400	340	1,073	11	2359	239
2032	3,522	2,440	3400	340	1,082	11	2359	239
2033	3,554	2,462	3400	340	1,092	11	2359	239
2034	3,585	2,484	3400	340	1102	11	2359	239
2035	3,617	2,506	3400	340	1,111	11	2359	239
2036	3,650	2,528	3400	340	1,121	11	2359	239
2037	3,682	2,551	3400	340	1,131	11	2359	239
2038	3,715	2,573	3400	340	1,142	11	2359	239
2039	3,748	2,596	3400	340	1,152	11	2359	239
2040	3,782	2,620	3400	340	1,162	11	2359	239

[a] 49-state analysis includes all states except California.

Table 7.1-27
49-State Marine Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm	Control Combo S ppm
2000	1779	1,350	3400	3400	428	340	2663	2663
2001	1,798	1,365	3400	3400	433	340	2663	2663
2002	1,818	1,380	3400	3400	438	340	2663	2663
2003	1,838	1,395	3400	3400	442	340	2663	2663
2004	1,858	1,410	3400	3400	447	340	2663	2663
2005	1,878	1,426	3400	3400	452	340	2663	2663
2006	1,899	1,442	3400	3400	457	186	2626	2626
2007	1,920	1,458	3400	1615	462	77	2600	1245
2008	1,941	1,474	3400	340	467	77	2600	277
2009	1,963	1,490	3400	340	473	77	2600	277
2010	1,984	1,507	3400	340	478	11	2584	261
2011	2,006	1,523	3400	340	483	11	2584	261
2012	2,029	1,540	3400	340	488	11	2584	261
2013	2,051	1,557	3400	340	494	11	2584	261
2014	2,074	1,575	3400	340	499	11	2584	261
2015	2,098	1,593	3400	340	505	11	2584	261
2016	2,121	1,610	3400	340	511	11	2584	261
2017	2,145	1,629	3400	340	516	11	2584	261
2018	2,170	1,647	3400	340	522	11	2584	261
2019	2,194	1,666	3400	340	528	11	2584	261
2020	2,219	1,685	3400	340	534	11	2584	261
2021	2,245	1,704	3400	340	540	11	2584	261
2022	2,271	1,724	3400	340	547	11	2584	261
2023	2,297	1,744	3400	340	553	11	2584	261
2024	2,323	1,764	3400	340	559	11	2584	261
2025	2,350	1,785	3400	340	566	11	2584	261
2026	2,378	1,805	3400	340	573	11	2584	261
2027	2,406	1,827	3400	340	579	11	2584	261
2028	2,434	1,848	3400	340	586	11	2584	261
2029	2,463	1,870	3400	340	593	11	2584	261
2030	2,492	1,892	3400	340	600	11	2584	261
2031	2,522	1,915	3400	340	607	11	2584	261
2032	2,552	1,938	3400	340	614	11	2584	261
2033	2,583	1,961	3400	340	622	11	2584	261
2034	2,614	1,985	3400	340	629	11	2584	261
2035	2,646	2,009	3400	340	637	11	2584	261
2036	2,678	2,033	3400	340	645	11	2584	261
2037	2,711	2,058	3400	340	653	11	2584	261
2038	2,744	2,084	3400	340	661	11	2584	261
2039	2,778	2,110	3400	340	669	11	2584	261
2040	2,813	2,136	3400	340	677	11	2584	261

[a] 49-state analysis includes all states except California.

Table 7.1-28
48-State Nonroad Land-based Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[b]	Control Combo S ppm[b]
2000	8,175	5,315	3400	3400	2,860	299	2318	2318
2001	8,410	5,468	3400	3400	2,942	299	2318	2318
2002	8,645	5,621	3400	3400	3,025	299	2318	2318
2003	8,880	5,773	3400	3400	3,107	299	2318	2318
2004	9,115	5,926	3400	3400	3,189	299	2318	2318
2005	9,350	6,079	3400	3400	3,271	299	2318	2318
2006	9,584	6,231	3400	3400	3,353	165	2271	2271
2007	9,817	6,383	3400	1615	3,435	69	2237	1075
2008	10,051	6,534	3400	340	3,516	69	2237	245
2009	10,284	6,686	3400	340	3598	69	2237	245
2010	10,518	6,838	3400	148	3,680	11	2217	100
2011	10,752	6,990	3400	11	3,762	11	2217	11
2012	10,987	7,143	3400	11	3,844	11	2217	11
2013	11,222	7,296	3400	11	3,926	11	2217	11
2014	11,456	7,448	3400	11	4,008	11	2217	11
2015	11,691	7,601	3400	11	4,090	11	2217	11
2016	11,923	7,752	3400	11	4,172	11	2217	11
2017	12,156	7,903	3400	11	4,253	11	2217	11
2018	12,388	8,054	3400	11	4,334	11	2217	11
2019	12,621	8,205	3400	11	4,415	11	2217	11
2020	12,853	8,356	3400	11	4,497	11	2217	11
2021	13,086	8,507	3400	11	4,578	11	2217	11
2022	13,318	8,659	3400	11	4,659	11	2217	11
2023	13,550	8,810	3400	11	4,741	11	2217	11
2024	13,783	8,961	3400	11	4,822	11	2217	11
2025	14,015	9,112	3400	11	4,903	11	2217	11
2026	14,246	9,262	3400	11	4,984	11	2217	11
2027	14,477	9,412	3400	11	5,065	11	2217	11
2028	14,708	9,562	3400	11	5,146	11	2217	11
2029	14,939	9,713	3400	11	5,227	11	2217	11
2030	15,170	9,863	3400	11	5,307	11	2217	11
2031	15,401	10,013	3400	11	5,388	11	2217	11
2032	15,632	10,163	3400	11	5,469	11	2217	11
2033	15,863	10,313	3400	11	5,550	11	2217	11
2034	16,094	10,463	3400	11	5,631	11	2217	11
2035	16,325	10,614	3400	11	5712	11	2217	11
2036	16,556	10,764	3400	11	5,792	11	2217	11
2037	16,787	10,914	3400	11	5,873	11	2217	11
2038	17018	11,064	3400	11	5,954	11	2217	11
2039	17,249	11,214	3400	11	6,035	11	2217	11
2040	17,480	11,364	3400	11	6,116	11	2217	11

[a] 48-state analysis includes all states except Alaska and Hawaii.
[b] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 and 48-state values, since the difference was negligible.

Table 7.1-29
48-State Locomotive Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[b]	Control Combo S ppm[b]
2000	2821	1,833	3400	3400	988	299	2396	2396
2001	2966	1,927	3400	3400	1,039	299	2396	2396
2002	2,918	1,896	3400	3400	1,022	299	2396	2396
2003	2969	1,929	3400	3400	1,040	299	2396	2396
2004	3,010	1,955	3400	3400	1,054	299	2396	2396
2005	3,051	1,982	3400	3400	1,069	299	2396	2396
2006	3,081	2,001	3400	3400	1079	165	2352	2352
2007	3,111	2,021	3400	1615	1,090	69	2321	1114
2008	3,124	2,030	3400	340	1,095	69	2321	252
2009	3,146	2,044	3400	340	1102	69	2321	252
2010	3,169	2,058	3400	340	1,110	11	2302	233
2011	3,223	2,094	3400	340	1,129	11	2302	233
2012	3,237	2,103	3400	340	1,134	11	2302	233
2013	3,246	2,109	3400	340	1,137	11	2302	233
2014	3,255	2,115	3400	340	1,140	11	2302	233
2015	3,270	2,124	3400	340	1,146	11	2302	233
2016	3,303	2,146	3400	340	1,157	11	2302	233
2017	3,322	2,158	3400	340	1,164	11	2302	233
2018	3,340	2,169	3400	340	1,170	11	2302	233
2019	3,358	2,182	3400	340	1,177	11	2302	233
2020	3,369	2,189	3400	340	1,181	11	2302	233
2021	3,399	2,208	3400	340	1,191	11	2302	233
2022	3,430	2,228	3400	340	1,202	11	2302	233
2023	3,460	2,248	3400	340	1,212	11	2302	233
2024	3,491	2,268	3400	340	1,223	11	2302	233
2025	3,522	2,288	3400	340	1,234	11	2302	233
2026	3,554	2,309	3400	340	1,245	11	2302	233
2027	3585	2,329	3400	340	1,256	11	2302	233
2028	3,617	2,350	3400	340	1,267	11	2302	233
2029	3,650	2,371	3400	340	1,279	11	2302	233
2030	3,682	2,392	3400	340	1,290	11	2302	233
2031	3,715	2,413	3400	340	1,302	11	2302	233
2032	3748	2,435	3400	340	1,313	11	2302	233
2033	3,782	2,457	3400	340	1,325	11	2302	233
2034	3,815	2,479	3400	340	1,337	11	2302	233
2035	3,849	2,501	3400	340	1,349	11	2302	233
2036	3,884	2,523	3400	340	1,361	11	2302	233
2037	3,918	2,546	3400	340	1,373	11	2302	233
2038	3,953	2,568	3400	340	1,385	11	2302	233
2039	3,989	2,591	3400	340	1,398	11	2302	233
2040	4,024	2614	3400	340	1410	11	2302	233

[a] 48-state analysis includes all states except Alaska and Hawaii.
[b] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 & 48-state values, since the difference was negligible. Similarly, the Locomotive and Marine combination sulfur levels have been set to their average to simplify the analysis.

Table 7.1-30
48-State Marine Diesel Fuel Volumes and Sulfur Content[a]

Year	Total Volume	Affected Volume	Base S ppm	Control S ppm	Spillover Volume	Spillover S ppm	Base Combo S ppm[b]	Control Combo S ppm[b]
2000	1786	1,273	3400	3400	513	299	2396	2396
2001	1,805	1,287	3400	3400	518	299	2396	2396
2002	1,825	1,301	3400	3400	524	299	2396	2396
2003	1,845	1,315	3400	3400	530	299	2396	2396
2004	1,865	1,330	3400	3400	535	299	2396	2396
2005	1,886	1,344	3400	3400	541	299	2396	2396
2006	1,906	1,359	3400	3400	547	165	2352	2352
2007	1,928	1,374	3400	1615	553	69	2321	1114
2008	1,949	1,389	3400	340	560	69	2321	252
2009	1,970	1,405	3400	340	566	69	2321	252
2010	1,992	1,420	3400	340	572	11	2302	233
2011	2,014	1,436	3400	340	578	11	2302	233
2012	2,037	1,452	3400	340	585	11	2302	233
2013	2,059	1,468	3400	340	591	11	2302	233
2014	2,082	1,485	3400	340	598	11	2302	233
2015	2,106	1,501	3400	340	605	11	2302	233
2016	2,130	1,518	3400	340	611	11	2302	233
2017	2,154	1,535	3400	340	618	11	2302	233
2018	2,178	1,553	3400	340	625	11	2302	233
2019	2,203	1,570	3400	340	632	11	2302	233
2020	2,228	1,588	3400	340	640	11	2302	233
2021	2,254	1,607	3400	340	647	11	2302	233
2022	2,279	1,625	3400	340	654	11	2302	233
2023	2,306	1,644	3400	340	662	11	2302	233
2024	2,333	1,663	3400	340	670	11	2302	233
2025	2,360	1,682	3400	340	677	11	2302	233
2026	2,387	1,702	3400	340	685	11	2302	233
2027	2,415	1,722	3400	340	693	11	2302	233
2028	2,444	1,742	3400	340	702	11	2302	233
2029	2,473	1,763	3400	340	710	11	2302	233
2030	2,502	1,784	3400	340	718	11	2302	233
2031	2,532	1,805	3400	340	727	11	2302	233
2032	2,562	1,827	3400	340	736	11	2302	233
2033	2,593	1,849	3400	340	745	11	2302	233
2034	2,624	1,871	3400	340	754	11	2302	233
2035	2,656	1,894	3400	340	763	11	2302	233
2036	2,689	1,917	3400	340	772	11	2302	233
2037	2,722	1,940	3400	340	781	11	2302	233
2038	2,755	1,964	3400	340	791	11	2302	233
2039	2,789	1,989	3400	340	801	11	2302	233
2040	2,824	2013	3400	340	811	11	2302	233

[a] 48-state analysis includes all states except Alaska and Hawaii.
[b] 50-state and 48-state Base and Control combination sulfur levels have been set to the average of 50 & 48-state values, since the difference was negligible. Similarly, the Locomotive and Marine combination sulfur levels have been set to their average to simplify the analysis.

7.1.5 Refinery Supply Volumes

After developing the 2008 volume estimates for the consumption of highway diesel fuel; nonroad, locomotive and marine diesel fuel and other non-highway distillate fuel, it was necessary to estimate the refinery supply volumes for each of these subpools to develop a baseline for the refinery cost analysis for the proposed rule. The refinery supply volumes are different from the consumption volumes because of the downgrade which occurs from the low sulfur highway diesel fuel pool to the high sulfur non-highway diesel fuel pool during the distribution between the refineries and the terminals. For the highway diesel rule promulgated in 2001, EPA estimated that downgrade would increase by 2.2 percent due to the 15 ppm highway diesel fuel sulfur standard which takes effect in 2006. EPA also estimated that there is already a 2.2 percent downgrade due to the current 500 ppm sulfur which results in a total of 4.4 percent downgrade from the highway diesel fuel pool to the non-highway distillate pool. The 4.4 percent downgrade was applied equally in each PADD and the resulting volumes are representative after any inter-PADD transfers have taken place. While the downgrade has not yet occurred in the refinery supply table, the spillover volume is considered the same between the two tables as this volume is an intended transfer from the highway to the nonroad diesel pool to avoid having to invest capital investments in the distribution system.

The 4.4 percent highway downgrade is accounted for by dividing the highway diesel fuel demand volume by 95.6 percent, and the downgraded highway diesel fuel was then added to the high sulfur distillate fuel pool. The highway diesel fuel downgrade is presumed to all go to the other non-highway distillate fuel (i.e., heating oil). This is a conservative estimate as it is likely that much of this downgraded volume would be under 500 ppm and could be downgraded to the 500 ppm pools, either the 500 ppm highway, nonroad, locomotive and marine diesel pools from 2006 to 2010, or to the 500 ppm locomotive and marine pool after 2010. This assumption will be reconsidered for the final rule.

The sulfur levels of the spillover volume for the refinery supply estimates were determined differently from the fuel demand estimates, which assumed the same proportion of highway 15/500 ppm fuel in each non-highway subpool as in the highway pool. For the supply estimates, we presumed all spillover into the NRLM diesel fuel is 15 ppm.

The result of the these adjustments in pool volumes to account for the downgrade in the distribution system is summarized in Table 7.1-31. These are the diesel fuel volumes that were used in the subsequent cost analysis.

Table 7.1-31
Summary of Diesel Fuel Supply by PADD for 2008 (million gallons)

Category	Fuel Type	1	2	3	4	5 AZ, NV, OR, WA	5 AK	5 HI	U.S. - CA	5 CA	U.S.
Revised Highway	total	13,000	14,158	7,156	1,859	2,398	115	42	38,728	3,236	41,964
	15ppm diesel	9,647	10,186	5,042	1,199	1,750	84	29	27,938	3,236	31,174
	500ppm diesel	3,353	3,972	2,113	659	648	31	14	10,790	0	10,790
	high S	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Land-Based Nonroad	total	2,166	3,559	2,273	822	567	66	32	9,486	663	10,149
	15ppm diesel	308	1,222	757	548	150	5	9	2,999	663	3,661
	500ppm diesel	0	0	0	0	0	0	0	0	0	0
	high S	1,858	2,337	1,517	274	417	62	23	6,488	0	6,488
Locomotive	total	509	1,256	700	351	116	4	0	2,936	193	3,129
	15ppm diesel	53	410	221	231	29	0	0	944	193	1,136
	500ppm diesel	0	0	0	0	0	0	0	0	0	0
	high S	456	846	479	120	87	4	0	1,992	0	1,992
Marine	total	481	295	1,014	0	60	78	13	1,941	99	2,040
	15ppm diesel	50	96	320	0	15	4	3	489	99	588
	500ppm diesel	0	0	0	0	0	0	0	0	0	0
	high S	431	199	693	0	45	74	10	1,452	0	1,452
Subtotal (NR, Loc, Marine)	total	3,156	5,111	3,987	1,173	743	149	45	14,364	955	15,318
	15ppm diesel	411	1,728	1,298	779	194	9	12	4,431	955	5,386
	500ppm diesel	0	0	0	0	0	0	0	0	0	0
	high S	2,745	3,382	2,689	394	549	140	33	9,932	0	9,932
Other Off-Highway	total	8,001	1,165	785	156	253	148	6	10,514	141	10,654
	15ppm diesel	681	409	247	106	63	6	1	1,513	141	1,654
	500ppm diesel	217	130	79	34	20	2	0	482	0	482
	high S	7,103	627	460	16	169	140	4	8,518	0	8,518
TOTAL	total	24,157	20,434	11,927	3,188	3,394	412	93	63,605	4,332	67,937
	15ppm diesel	10,739	12,323	6,587	2,085	2,008	99	42	33,882	4,332	38,214
	500ppm diesel	3,570	4,102	2,192	693	668	33	14	11,272	0	11,272
	high S	9,848	4,009	3,148	410	718	280	37	18,451	0	18,451

For using the supply volumes in Table 7.1-31 for estimating the cost-effectiveness of the analysis contained in Chapter 8, it is necessary to project the supply volumes into future years for the Proposed Two Step NRLM fuel program and the other options considered. This was done using the applicable growth rates for each respective pool, considering the volume of small refiner NRLM diesel fuel which is exempted from having to comply during the two exemption periods (2007 to 2010, and 2010 to 2014), and considering the increased spillover of 500 ppm and 15 ppm sulfur diesel fuel into the heating oil market. Spillover increases because refineries in PADD 2 and 4 are not expected to be able to sell off their current high sulfur distillate pool solely into the heating oil market.

The following table provide the base volumes used for estimating the total volume of 500 ppm diesel fuel and the total volume of 15 ppm diesel fuel affected by the Proposed Two step Nonroad Program (this table is only shown for the Proposed Two Step fuel program).

Table 7.1-34 Future nonhighway Supply volumes for the U.S. outside of California for the Proposed Two Step NRLM Program (MMGallons/yr)

	Nonroad				Locomotive				Marine				Heating Oil	Heating Oil
Year	Total Volume	HS Pool and Affected Volume	Small Refiner Exempted Volume	Spillover Volume	Total Volume	HS Pool and Affected Volume	Small Refiner Exempted Volume	Spillover Volume	Total Volume	HS Pool and Affected Volume	Small Refiner Exempted Volume	Spillover Volume	Other Affected Volume (new spillover) 500 ppm	Other Affected Volume (new spillover) 15 ppm\
2000	7,716	5,277		2,439	2,651	1,799		852	1,779	1,331		448	0	0
2001	7,938	5,429		2,509	2,787	1,892		896	1,798	1,345		453	0	0
2002	8,160	5,580		2,579	2,742	1,861		881	1,818	1,360		458	0	0
2003	8,382	5,732		2,649	2,790	1,893		897	1,838	1,375		463	0	0
2004	8,603	5,884		2,720	2,828	1,919		909	1,858	1,390		468	0	0
2005	8,825	6,036		2,790	2,867	1,946		922	1,878	1,405		473	0	0
2006	9,046	6,186		2,859	2,895	1,964		930	1,899	1,421		478	0	0
2007	9,266	5,654	683	2,929	2,923	1,770	214	940	1,920	1,282	155	484	636	0
2008	9,486	5,788	700	2,999	2,936	1,778	215	944	1,941	1,296	157	489	642	0
2009	9,707	5,923	716	3,068	2,956	1,790	216	950	1,963	1,310	158	494	648	0
Jan-May '10	9,927	6,057	732	3,138	2,977	1,803	218	957	1,984	1,325	160	500	654	0
Jun-Dec '10	9,927	5,893	1034	3,000	2,977	1,951		1,026	1,984	1,416		569	556	98
2011	10,149	6,025	1057	3,067	3,028	1,985		1,044	2,006	1,431		575	561	99
2012	10,370	6,156	1080	3,134	3,042	1,994		1,048	2,029	1,447		581	567	100
2013	10,591	6,288	1103	3,201	3,050	1,999		1,051	2,051	1,463		588	572	101
Jan-May '14	10,813	6,419	1126	3,268	3,059	2,005		1,054	2,074	1,480		595	577	102
Jun-Dec '14	10,813	7,545		3,268	3,059	2,005		1,054	2,074	1,480		595	577	102
2015	11,034	7,700		3,334	3,073	2,014		1,059	2,098	1,496		601	583	103
2016	11,254	7,853		3,401	3,104	2,034		1,070	2,121	1,513		608	588	104
2017	11,473	8,006		3,467	3,122	2,046		1,076	2,145	1,530		615	593	105
2018	11,693	8,159		3,533	3,138	2,057		1,081	2,170	1,548		622	599	106
2019	11,912	8,312		3,600	3,156	2,068		1,087	2,194	1,565		629	605	107
2020	12,131	8,465		3,666	3,166	2,075		1,091	2,219	1,583		636	610	108
2021	12,351	8,619		3,732	3,194	2,094		1,101	2,245	1,601		643	616	109
2022	12,570	8,772		3,799	3,223	2,112		1,111	2,271	1,620		651	622	110
2023	12,790	8,925		3,865	3,252	2,131		1,120	2,297	1,638		658	627	111
2024	13,009	9,078		3,931	3,281	2,150		1,130	2,323	1,657		666	633	112
2025	13,228	9,231		3,998	3,310	2,169		1,141	2,350	1,677		674	639	113
2026	13,446	9,383		4,063	3,339	2,189		1,151	2,378	1,696		682	645	114
2027	13,664	9,535		4,129	3,369	2,208		1,161	2,406	1,716		690	651	115
2028	13,882	9,687		4,195	3,399	2,228		1,171	2,434	1,736		698	657	116
2029	14,100	9,839		4,261	3,430	2,248		1,182	2,463	1,757		706	663	117
2030	14,318	9,992		4,327	3,460	2,268		1,192	2,492	1,778		714	669	118
2031	14,536	10,144		4,393	3,491	2,288		1,203	2,522	1,799		723	676	119
2032	14,754	10,296		4,459	3,522	2,308		1,214	2,552	1,820		731	682	120
2033	14,972	10,448		4,525	3,553	2,329		1,224	2,582	1,842		740	688	121
2034	15,190	10,600		4,590	3,585	2,350		1,235	2,613	1,864		749	695	123
2035	15,408	10,752		4,656	3,617	2,371		1,246	2,644	1,886		758	701	124
2036	15,626	10,904		4,722	3,649	2,392		1,257	2,675	1,908		767	708	125

The following table summarizes the estimated volume of 500 ppm diesel fuel and 15 ppm diesel fuel affected by the Proposed Two step Nonroad Program by each year from 2007 to 2036. The spillover of highway into the NRLM diesel pools and the total volume of NRLM diesel fuel is also presented.

Table 7.1-35 Future nonhighway Supply volumes for U.S. outside of California for the Proposed Two Step NRLM Program (MMGallons/yr)

Totals (NR, Loc & Mar)

Year	Total Volume	Affected Volume for 500 ppm			Affected Volume for 15 ppm		Spillover Volume
		2007-2010	2010-2014	2014+	2010-2014	2014+	
2000	12,145						3,739
2001	12,523						3,858
2002	12,719						3,918
2003	13,009						4,009
2004	13,289						4,096
2005	13,571						4,184
2006	13,839						4,268
2007	14,745	5,449					4,352
2008	15,006	9,504					4,431
2009	15,274	9,671					4,513
Jan-May '10	15,543	4,099					4,595
Jun-Dec '10	15,543		2,892		3,495		4,595
2011	15,844		5,034		6,124		4,685
2012	16,107		5,088		6,256		4,763
2013	16,366		5,137		6,389		4,840
Jan-May '14	16,625		2,162		2,717		4,916
Jun-Dec '14	16,625			2,369		4,461	4,916
2015	16,890			4,093		7,803	4,995
2016	17,171			4,136		7,957	5,078
2017	17,438			4,170		8,111	5,158
2018	17,705			4,203		8,265	5,237
2019	17,973			4,238		8,419	5,316
2020	18,235			4,268		8,573	5,393
2021	18,514			4,311		8,727	5,476
2022	18,795			4,354		8,881	5,560
2023	19,076			4,397		9,035	5,644
2024	19,358			4,441		9,190	5,728
2025	19,641			4,485		9,344	5,812
2026	19,923			4,530		9,497	5,896
2027	20,205			4,575		9,650	5,980
2028	20,489			4,621		9,803	6,064
2029	20,773			4,668		9,956	6,149
2030	21,058			4,715		10,110	6,234
2031	21,344			4,763		10,263	6,319
2032	21,631			4,811		10,416	6,404
2033	21,918			4,859		10,569	6,489
2034	22,205			4,908		10,723	6,575
2035	22,494			4,958		10,876	6,660
2036	22,783			5,008		11,029	6,746

The following table summarizes the estimated volume of 500 ppm diesel fuel and 15 ppm diesel fuel affected by the One step Nonroad Program (Option #1) by each year from 2008 to 2036. The spillover of highway into the NRLM diesel pools and the total volume of NRLM diesel fuel is also presented.

Table 7.1-36 - Future nonhighway Supply volumes for the U.S. outside of California for the One Step Program with Locomotive and Marine to 500 and NR to 15 in 2008 (MMGallons/yr)

Totals (NR, Loc & Mar)						
Year	Total Volume	Affected Volume for 500 ppm		Affected Volume for 15 ppm		Spillover Volume
		2008-2012	2012+	2008-2012	2012+	
2000	12,145					3,739
2001	12,523					3,858
2002	12,719					3,918
2003	13,009					4,009
2004	13,289					4,096
2005	13,571					4,184
2006	13,839					4,268
2007	14,109					4,352
Jan-May '08	14,364					4,431
Jun-Dec '08	15,006	2,251		3,293		4,431
2009	15,274	3,892		5,775		4,511
2010	15,543	3,927		5,905		4,591
2011	15,844	3,981		6,035		4,682
Jan-May '12	16,107	1,671		2,569		4,760
Jun-Dec '12	16,107		2,343		4,280	4,760
2013	16,372		4,043		7,493	4,836
2014	16,631		4,071		7,648	4,912
2015	16,896		4,102		7,804	4,991
2016	17,177		4,145		7,958	5,074
2017	17,445		4,179		8,112	5,154
2018	17,711		4,213		8,266	5,233
2019	17,980		4,248		8,420	5,312
2020	18,241		4,278		8,574	5,389
2021	18,521		4,321		8,728	5,472
2022	18,802		4,363		8,882	5,556
2023	19,083		4,407		9,036	5,640
2024	19,365		4,451		9,191	5,723
2025	19,648		4,495		9,345	5,808
2026	19,930		4,540		9,498	5,891
2027	20,213		4,586		9,651	5,976
2028	20,496		4,632		9,804	6,060
2029	20,781		4,679		9,958	6,144
2030	21,066		4,726		10,111	6,229
2031	21,351		4,773		10,264	6,314
2032	21,638		4,822		10,417	6,399
2033	21,925		4,870		10,571	6,485
2034	22,213		4,919		10,724	6,570
2035	22,502		4,969		10,877	6,656
2036	22,783		5,012		11,029	6,742

The following table summarizes the estimated volume of 500 ppm diesel fuel and 15 ppm diesel fuel affected by the Two Step Nonroad Program with the 15 ppm sulfur standard being met in 2009 (Option #2c) by each year from 2008 to 2036. The spillover of highway into the NRLM diesel pools and the total volume of NRLM diesel fuel is also presented.

Table 7.1-37 - Future nonhighway Supply volumes for the U.S. outside of California for the Nonroad Program which goes to 15 ppm in 2009 instead of 2010 (MMGallons/yr)

Totals (NR, Loc & Mar)

Year	Total Volume	Affected Volume for 500 ppm			Affected Volume for 15 ppm		Spillover Volume
		2007-2009	2009-2013	2013+	2009-2013	2013+	
2000	12,145						3,739
2001	12,523						3,858
2002	12,719						3,918
2003	13,009						4,009
2004	13,289						4,096
2005	13,571						4,184
2006	13,839						4,268
2007	14,745	5,449					4,352
2008	15,006	9,504					4,431
Jan-May '09	15,274	3,731					5,229
Jun-Dec '09	15,274		2,859		3,418		5,296
2010	15,543		4,959		5,423		5,161
2011	15,844		5,036		5,543		5,264
2012	16,107		5,089		5,663		5,355
Jan-May '13	16,366		2,141		2,409		5,444
Jun-Dec '13	16,366			2,354		4,370	5,444
2014	16,625			4,063		7,647	4,914
2015	16,890			4,095		7,803	4,993
2016	17,171			4,137		7,957	5,076
2017	17,438			4,172		8,111	5,156
2018	17,705			4,205		8,265	5,235
2019	17,973			4,240		8,419	5,314
2020	18,235			4,270		8,573	5,391
2021	18,514			4,313		8,727	5,474
2022	18,795			4,356		8,881	5,558
2023	19,076			4,399		9,035	5,642
2024	19,358			4,443		9,190	5,726
2025	19,641			4,487		9,344	5,810
2026	19,923			4,532		9,497	5,894
2027	20,205			4,578		9,650	5,978
2028	20,489			4,624		9,803	6,062
2029	20,773			4,670		9,956	6,147
2030	21,058			4,717		10,110	6,231
2031	21,344			4,765		10,263	6,316
2032	21,631			4,813		10,416	6,402
2033	21,918			4,861		10,569	6,487
2034	22,205			4,910		10,723	6,572
2035	22,494			4,960		10,876	6,658
2036	22,783			5,010		11,029	6,744

The following table summarizes the estimated volume of 500 ppm diesel fuel and 15 ppm diesel fuel affected by the Two Step Nonroad Program with locomotive and marine diesel fuel complying with the 15 ppm sulfur standard along with nonroad in 2010 (Option #4) by each year from 2008 to 2036. The spillover of highway into the NRLM diesel pools and the total volume of NRLM diesel fuel is also presented.

Table 7.1-38 Future nonhighway Supply volumes for the U.S. outside of California for the Nonroad Program which has Locomotive and Marine going to 15 ppm in 2010 along with Nonroad (MMGallons/yr)

Totals (NR, Loc & Mar)							
Year	Total Volume	Affected Volume for 500 ppm			Affected Volume for 15 ppm		Spillover Volume
		2007-2010	2010-2014	2014+	2010-2014	2014+	
2000	12,145						3,739
2001	12,523						3,858
2002	12,719						3,918
2003	13,009						4,009
2004	13,289						4,096
2005	13,571						4,184
2006	13,839						4,268
2007	14,745	5,449					4,352
2008	15,006	9,504					4,431
2009	15,274	9,671					4,513
Jan-May '10	15,543	4,099					4,595
Jun-Dec '10	15,543		654		5,851		4,392
2011	15,843		1,146		10,217		4,480
2012	16,107		1,171		10,380		4,557
2013	16,366		1,196		10,538		4,632
Jan-May '14	16,625		509		4,457		4,707
Jun-Dec '14	16,625					6,952	4,707
2015	16,890					12,106	4,784
2016	17,171					12,305	4,865
2017	17,438					12,496	4,943
2018	17,705					12,685	5,020
2019	17,973					12,875	5,098
2020	18,235					13,061	5,173
2021	18,514					13,260	5,254
2022	18,795					13,459	5,336
2023	19,076					13,659	5,417
2024	19,358					13,859	5,499
2025	19,641					14,060	5,580
2026	19,923					14,261	5,662
2027	20,205					14,462	5,744
2028	20,489					14,663	5,826
2029	20,773					14,865	5,908
2030	21,058					15,068	5,990
2031	21,344					15,271	6,073
2032	21,630					15,475	6,155
2033	21,918					15,680	6,238
2034	22,205					15,884	6,321
2035	22,494					16,090	6,404
2036	22,783					16,296	6,488

7.2 Refining Costs

The most significant cost involved in providing diesel fuel which meets more stringent sulfur standards is the cost of removing the sulfur at the refinery. In this section, we describe the methodology used and present the estimated costs for refiners to:

- comply with the proposed 2007 Nonroad, Locomotive and Marine (NRLM) diesel fuel sulfur standards and the 2010 nonroad diesel fuel standards,
- comply with other NRLM diesel fuel sulfur options considered, and
- comply with the already promulgated 2006 highway diesel fuel sulfur standards (an update of a previous cost analysis).

Finally, we compare our estimated costs to those developed by others who have evaluated the refining costs of meeting tighter sulfur caps for non-highway diesel fuel.

7.2.1 Methodology

7.2.1.1 Overview

This section describes the methodology used to estimate the refining cost of reducing diesel fuel sulfur content. Costs are estimated based on three distinct desulfurization technologies: conventional hydrotreating, the Linde Iso-Therming process and the Phillips SZorb adsorption process. Conventional hydrotreating cost estimates were based on information from two vendors, while the cost estimates for the other two more advanced processes was made from information provided by the respective vendors. For all three technologies, costs are estimated for each U.S. refinery currently producing distillate fuel. Conventional hydrotreating technology was projected to be used to desulfurize distillate to meet a 500 ppm sulfur cap. A mix of primarily advanced desulfurization technologies with some conventional hydrotreating technology was projected to be used to meet the 15 ppm sulfur cap. This mix of technology varied depending on the timing of the 15 ppm sulfur standard. To meet the 500 ppm and 15 ppm sulfur cap standards, refiners are expected to have to desulfurize to 340 ppm and 7 ppm, respectively.

Refining costs were developed for revamping existing hydrotreaters which produce low sulfur diesel fuel, as well as new, grass roots desulfurization units. The lower revamped costs were primarily used when streams or parts of streams were already desulfurized (i.e., highway), while the grassroots costs applied normally for untreated streams (mostly nonroad). In both cases, costs were developed for our refinery cost model and used to estimated the desulfurization cost for each refinery in the U.S. producing distillate fuel in 2000. These refinery-specific costs consider the volume of distillate fuel produced, the composition of this distillate fuel, the location of the refinery (e.g., Gulf Coast, Rocky Mountain region, etc.). The estimated composition of each refinery's distillate included the fraction of hydrotreated and nonhydrotreated straight run distillate, light cycle oil (LCO), other cracked stocks (coker, visbreaker, thermal cracked) and hydrocracked distillate, and the cost to desulfurize each of those stocks. The cost information provided by the various vendors was used to develop the desulfurization cost for each blendstock, however, when lacking, engineering judgement was used to develop the needed specific cost estimate. The average desulfurization cost for each refinery was based on the volume-weighted average of desulfurizing each of those blendstocks. The production volumes used were those indicative of the year 2008, the first full year that the proposed NRLM diesel fuel program would be applicable.

7.2.1.2 Basic Cost Inputs for Specific Desulfurization Technologies

To obtain a comprehensive basis for estimating the cost of desufurizing diesel fuel, over the past few years we have held meetings with a large number of vendors of desulfurization technologies. These firms include: Criterion Catalyst, UOP, Akzo Nobel, Haldor Topsoe, Phillips, and Linde. We have also met with numerous refiners of diesel fuel considering the use of these technologies and reviewed the literature on this subject. The information and estimates described below represent the culmination of these efforts.

The information used in our refinery cost model for estimating the cost of meeting 500 and 15 ppm sulfur caps using conventional hydrotreating is presented first. The cost methodology for conventional hydrotreating was developed for the 2007 highway diesel fuel rulemaking. Only the final process design parameters are presented here. For a complete description of the methodology used to develop the cost estimates for conventional hydrotreating, the reader should consult the Chapter 5 of the Regulatory Impact Analysis for the 2007 highway diesel fuel rule. The few variations from the methodology described in that RIA are described below.

Next we present the methodology and resulting cost information used for developing the refinery costs for the Phillips adsorption and Linde Iso-Therming processes. In this case, we begin by presenting the estimates of the process design parameters provided by the developers of these processes. These projections are then evaluated to produce sets of process design parameters which can be used to estimate the cost of meeting 500 ppm and 15 ppm NRLM diesel fuel standards for each domestic refiner. The resulting refining cost projections are presented and discussed in Section 7.2.2.

7.2.1.2.1 Conventional Desulfurization Technology

The cost of desulfurizing diesel fuel includes the capital cost related to designing and constructing the desulfurization unit, as well as the cost of operating the unit. We were able to obtain fairly compete sets of such process design paramters from two out of the five or six licensors of conventional desulfurization technologies.[9] [10] [11] These designs addressed the production of 15 ppm diesel fuel by retrofitting existing hydrotreaters originally designed to produce 500 ppm diesel fuel, as well as building new, grass roots units. These two sets of process design parameters were also used to estimate the cost of hydrotreating high sulfur diesel fuel down to 500 ppm.

In addition to the information obtained from these two vendors, we reviewed similar information submitted to the National Petroleum Council (NPC) by Akzo Nobel, Criterion, Haldor Topsoe, UOP and IFP for its study of diesel fuel desulfurization costs and discussed them with the vendors.[12] These submissions were generally not as comprehensive as those provided by the two vendors mentioned above. In all cases, these submissions corroborated the costs from the two vendors.

All of the vendors indicated that operating pressures of no more than 900 pounds per square inch (psi) would be sufficient to produce fuel meeting a 15 ppm sulfur cap. Most of the vendors projected that 650 psi would be sufficient. Likewise, a number of refiners have indicated that pressures well below 1000 psi would be sufficient. A contractor for API has indicated that they believe that a 850 psi unit is all that is necessary meet a 15 ppm cap standard, although the contractor also stated that lower pressure units would not be sufficient. Thus, we based our estimate of capital cost on two different vendor submissions which were based on units operating at 650 and 900 psi pressure.

Based on the information obtained from the two vendors of conventional hydrotreating technologies, as well as that obtained from Phillips and Linde, we project that refiners would use conventional hydrotreating to produce NRLM diesel fuel meeting the proposed 500 ppm standard in 2007. This unit would include heat exchangers, a fired pre-heater, a reactor, a hydrogen compressor and a make up compressor, and both high pressure and low pressure strippers. The refinery would also require a source of new hydrogen, an amine scrubber and a sulfur plant. Most all refineries already have sources of hydrogen, an amine scrubber and a sulfur plant. However, considering the hydrogen demand for complying with Tier 2 sulfur standards for gasoline and the 15 ppm cap on highway diesel sulfur, no residual refinery production hydrogen is expected to exist. Thus, we project that any new hydrogen demand would likely have to be produced from natural gas, either on-site or by a third party. Likewise, modest expansions of its amine scrubber and sulfur plant would be required.

Producing diesel fuel meeting a 15 ppm standard generally requires much greater reactor volume and a larger hydrogen capacity, both in terms of compressor capacity and ability to introduce this hydrogen into the reactor, than are required to meet a 500 ppm cap. Since the 15 ppm sulfur cap for nonroad diesel fuel would follow the 500 ppm NRLM sulfur cap by only three years, we project that refiners would have designed any new hydrotreaters built in 2007 to be easily retrofitted with additional equipment, such as a second reactor, a hydrogen compressor, a recycle scrubber, an inter-stage stripper and other associated process hardware. The technical approach described by each vendor to achieve a 15 ppm diesel fuel sulfur cap (average level of 7-8 ppm) is summarized in Table 7.2-1.

Table 7.2-1
Modifications Necessary to Reduce 500 ppm Sulfur Levels to 15 ppm

Diesel Fuel Sulfur Level	Vendor A	Vendor B
7-8 ppm (15 ppm cap)	Change to a more active catalyst Install recycle gas scrubber Modify compressor Install a second reactor, high pressure (900 psi) Use existing hot oil separator for inter-stage stripper	Change to a more active catalyst Install a recycle gas scrubber Install a second reactor (650 psi) Install a color reactor Install an interstage stripper

The vendors assumed that the existing highway desulfurization unit in place could be utilized (revamped) to comply with the 15 ppm sulfur standards. This includes a number of hydrotreater sub-units which are necessary for desulfurization and would save on both capital and operating costs for a two stage revamp compared to whole new grassroots unit. These sub-units include heat exchangers, a heater, a reactor filled with catalyst, two or more vessels used for separating hydrogen and any light ends produced by cracking during the desulfurization process, a compressor, and sometimes a hydrogen recycle gas scrubber. The desulfurization subunits listed here are discussed in detail in the feasibility section contained in Chapter 5.

In order to estimate the cost of meeting the proposed NRLM diesel fuel sulfur standards, it was necessary to evaluate three situations which would be faced by refiners: 1) producing NRLM diesel fuel meeting a 15 ppm cap from diesel fuel already being hydrotreated to meet a 500 ppm cap (i.e., a highway revamp), 2) producing NRLM diesel fuel meeting a 15 ppm cap from high sulfur distillate (i.e., grass roots 15 ppm hydrotreater), and 3) producing NRLM diesel fuel meeting a 500 ppm cap from high sulfur distillate (i.e., grass roots 500 ppm hydrotreater). Sets of process design parameters for the first two of these desulfurization configurations were developed for the highway rule. As discussed above, only the results of the previous derivations are presented below. The third configuration was not addressed for the highway diesel fuel rule, as highway diesel fuel was already meeting a 500 ppm cap. The section which develops the process design parameters for this third configuration includes a short description of the methodology used in its development, as it is very similar to those used to develop the first two sets of process design parameters.

One straightforward adjustment was made to all the capital costs developed for the 2007 highway diesel fuel rule. The capital costs developed for that rule were in terms of 1999 dollars. These costs were increased by 2.5% to reflect construction costs in 2002 dollars.[13]

7.2.1.2.1.2 Revamping to Process 500 ppm Diesel Fuel to Meet a 15 ppm Cap

These process design projections developed in this section would apply to a revamp of an existing desulfurization unit with additional hardware to enable the combined older and new unit to meet a 15 ppm sulfur cap. The portion of these projections which apply to operating costs are also relevant if a refiner would decide to replace their existing diesel fuel desulfurization unit with a new grassroots unit. In this case, the entire capital cost of the grass roots unit would be incurred. However, the incremental operating costs would be those of the new grass roots unit less those of the existing hydrotreater (which are developed in this section).

The process design parameters shown below were taken directly from those shown in the RIA for the 2007 highway diesel fuel rule, with one adjustment. Diesel fuel complying with the current 500 ppm sulfur standard typically contains 340 ppm sulfur. We expect refiners complying with the proposed 500 ppm NRLM diesel fuel sulfur cap would also desulfurize down to roughly 340 ppm sulfur. Thus, in revamping an existing 500 ppm hydrotreater to comply with a 15 ppm cap, refiners would have to desulfurize from 340 ppm down to 7 ppm. This is analogous to what we assumed in the analysis for the 2007 highway diesel fuel rule.

However, after the highway diesel fuel rule was finalized, it became evident that the vendor projections assumed a starting sulfur level of 500 ppm and not 340 ppm. Thus, the vendor projections assumed more desulfurization would be needed than is the case here. Based on a curve of hydrogen consumption versus initial and final sulfur level, developed in the Draft RIA to the 2007 highway diesel fuel rule, reducing the initial sulfur level from 500 ppm to 340 ppm reduces hydrogen consumption by 3.5%. We assumed that all cost-related parameters (capital cost, catalyst cost, yield losses, and utilities) would be reduced by the same 3.5%.

Table 7.2-6 presents the process design parameters for desulfurizing 500 ppm sulfur diesel fuel to meet a 15 ppm cap standard.[B]

[B] There are no tables numbered 7.2-2 through 7.2-5.

Table 7.2-6
Process Projections for Revamping an Existing Diesel Fuel Hydrotreater Desulfurizing Diesel Fuel Blendstocks from 500 ppm Cap to 15 ppm Cap

	Straight Run	Other Cracked Stocks	Light Cycle Oil
Capacity (BPSD)	25,000	25,000	25,000
Capital Cost (ISBL) ($million)	16	19	22
Liquid Hour Space Velocity (hr^{-1})	1.25	0.7	0.6
Hydrogen Consumption (scf/bbl)	93	223	362
Electricity (kW-hr/bbl)	0.4	0.7	0.8
HP Steam (lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	40	70	80
Catalyst Cost ($/BPSD)	0.2	0.4	0.5
Yield Loss (wt%)			
Diesel	1.0	1.9	2.1
Naphtha	-0.7	-1.3	-1.4
LPG	-0.04	-0.07	-0.08
Fuel Gas	-0.04	-0.11	-0.13

7.2.1.2.1.3 Process Design Projections for a Grassroots Unit Producing 15 ppm Fuel

The process design parameters presented in this section were taken directly from those derived in the RIA for the 2007 highway diesel fuel rule. These costs would apply primarily to refineries only producing, or predominantly producing, high sulfur diesel fuel today. In addition, the capital cost portion of these costs would apply to a a refinery which replaced an existing hydrotreater with a grassroots unit instead of revamping their existing hydrotreater. In this case, these refiners would incur the capital costs outlined here, but their operating costs would be based on a revamp as described above. Most refineries which currently produce high sulfur distillate fuel also produce some highway diesel fuel. In this case, we project costs which reflect those of a revamp and a grass roots unit. The methodology for this merging of the two costs is described in Section 7.2.1.5 below.

Table 7.2-7 presents the process design parameters for desulfurizing high sulfur distillate fuel to meet a 15 ppm cap standard in a grassroots unit.

Table 7.2-7
Process Projections for Installing a New Grassroots Unit for Desulfurizing Untreated Distillate Fuel Blendstocks to Meet a 15 ppm Cap Standard

	Straight Run	Other Cracked Stocks	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	31	37	42
Liquid Hour Space Velocity (Hr^{-1})	0.8	0.5	0.4
Hydrogen Consumption (SCF/bbl)	240	850	1100
Electricity (KwH/bbl)	0.6	1.1	1.2
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	60	105	120
Catalyst Cost ($/BPSD)	0.3	0.6	0.8
Yield Loss (%)			
Diesel	1.5	2.9	3.3
Naphtha	1.1	2.0	2.3
LPG	0.06	0.11	0.12
Fuel Gas	0.06	0.17	0.20

Unlike processing highway diesel fuel which is assumed to contain 340 ppm sulfur, the sulfur content of high sulfur distillate fuel can vary dramatically from refiner to refiner and region to region. A adjustment in hydrogen consumption was made for differing starting sulfur levels. The basis for the amount of sulfur needed to be removed is that the starting feed, comprised of 69 percent straight run, 23 percent LCO and 8 percent cracked stocks, contains 9000 ppm sulfur (0.9 weight percent). However, as described below in Subsection 7.2.1.3, the average concentration of sulfur in the overall distillate pool, and especially that part of the pool which is untreated, varies by PADD. After estimating what this sulfur level is, we adjusted the hydrogen consumption for this varying sulfur level (According to Vendor B, removing sulfur from diesel fuel consumes 125 scf/bbl for each weight percent of sulfur removed.[14]) We did not adjust the hydrogen consumption for the other qualities, polyaromatics and olefins, because we do not believe that these would likely vary independently with the sulfur level. Since the removal of sulfur consumes less than half the estimated hydrogen consumed as untreated 9000 ppm is desulfurized to 15 ppm, the adjustment is always less than 50 percent. The adjustment is applied as an adjustment ratio to each untreated blendstock type for a refinery with a distillate hydrotreater. The adjustment ranged from 0.79 for PADD 5, which has an estimated untreated distillate sulfur level of 2610 ppm, to 1.1 for PADD 3 which has an estimated untreated distillate sulfur level of 11,320 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our adjustment to account for differing starting sulfur levels assumes that they currently blend only unhydrotreated blendstocks into the distillate which comprises the high sulfur pool. Thus, we are making our adjustments based on a lower starting sulfur level. Our adjustment for these refineries ranged from 0.79 for PADD 5, which has an estimated untreated sulfur level of 2540 ppm, to 0.87 for PADD 3 which has a starting sulfur level of 5200 ppm, for these refineries without a distillate hydrotreater. The various hydrogen consumption adjustment values are summarized in Table 7.2-8.[C]

Table 7.2-8
Hydrogen Consumption Adjustment Factors: Revamped Units

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.90	0.88	1.1	0.84	0.79
No Distillate HT	0.81	0.80	0.87	0.79	0.79

7.2.1.2.1.4 Desulfurizing High Sulfur Distillate Fuel to a 500 ppm Cap

Finally, we needed to provide inputs for our cost model for desulfurizing untreated, high sulfur distillate to meet a 500 ppm sulfur cap standard, which is the first step of our two step program. These inputs are estimated by simply subtracting the inputs for the revamped unit for desulfurizing 500 ppm diesel fuel down to 15 ppm from the inputs for a grassroots unit for desulfurizing untreated diesel fuel down to 15 ppm. The untreated to 500 ppm inputs for our refinery cost model are summarized in Table 7.2-10.

[C] There is no table numbered 7.2-9.

Table 7.2-10
Process Projections for Installing a New Unit for Desulfurizing
Untreated Diesel Fuel Blendstocks to Meet a 500 ppm Sulfur Cap Standard

	Straight Run	Coker Distillate	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	16	19	21
Liquid Hour Space Velocity (Hr^{-1})	2.4	1.9	1.3
Hydrogen Consumption (SCF/bbl)	147	628	738
Electricity (KwH/bbl)	0.2	0.4	0.4
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	21	37	43
Catalyst Cost ($/BPSD)	0.1	0.2	0.3
Yield Loss (%)			
Diesel	0.5	1.1	1.2
Naphtha	-0.4	-0.7	-0.85
LPG	-0.02	-0.04	-0.04
Fuel Gas	-0.02	-0.06	-0.07

Again, a hydrogen consumption adjustment was made for starting sulfur levels which differ from 9000 ppm. In this case, the hydrogen adjustment ended up being larger than the grassroots desulfurization unit as the adjustment to the hydrogen consumption for going from untreated to 500 ppm comprises a larger percentage of the total hydrogen consumption. The adjustment is applied as an adjustment ratio to each blendstock type and it ranged from 0.67 for PADD 5, which has an estimated untreated distillate sulfur level of 2610 ppm, to 1.12 for PADD 3 which has an estimated untreated distillate sulfur level of 11,320 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our analysis does not assume that they currently hydrotreat any of the distillate which comprises the high sulfur pool. Thus, we estimate a starting sulfur level which is somewhat lower. Our adjustment for these refineries ranged from 0.67 for PADD 5, which has an estimated untreated sulfur level of 2540 ppm, to 0.80 for PADD 3 which has a starting sulfur level of 5200 ppm. The various hydrogen consumption adjustment values are summarized in Table 7.2-11.

Table 7.2-11
Hydrogen Consumption Adjustment Factors: Revamped Units

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.85	0.82	1.1	0.75	0.67
No Distillate HT	0.71	0.69	0.80	0.68	0.67

7.2.1.2.1.5 Hydrocrackate Processing and Tankage Costs

We believe that refineries with hydrocrackers will have to invest some capital and incur some operating costs to ensure that recombination reactions at the exit of the second stage of their hydrocracker do not cause the diesel fuel being produced by their hydrocracker to exceed the cap standard. The hydrocracker is a very severe hydrotreating unit capable of hydrotreating its product from thousands of ppm sulfur to essentially zero ppm sulfur, however, hydrogen sulfide recombination reactions which occur at the end of the cracking stage, and fluctuations in unit operations, such as temperature and catalyst life, can result in the hydrocracker diesel product having up to 30 ppm sulfur in its product stream.[15 16] Thus, refiners may need to install a finishing reactor for the diesel stream produced by the hydrocracker. According to vendors, this finishing reactor is a low temperature, low pressure hydrotreater which can desulfurize the simple sulfur compounds which are formed in the cracking stage of the hydrocracker.

Additionally, since the 15 ppm diesel sulfur standard is a very stringent cap standard, we are taking into account tankage that would likely be needed. We believe that refiners could store high sulfur batches of highway diesel fuel or nonroad diesel fuel during a shutdown of the diesel fuel hydrotreater. Diesel fuel production would cease in the short term, but the rest of the refinery could remain operative. To account for this, we provided for the cost in our cost model of the installation of a tank that would store 10 days of 15 ppm sulfur diesel production sufficient for a 10 day emergency turnaround which is typical for the industry, which would be about 3 million dollars for a 270,000 barrel storage tank.[17] This amount of storage should be adequate for most unanticipated turnarounds. We presumed that each refinery would need to add such storage, (for some refineries, off-spec diesel fuel could also be sold as high sulfur heating oil or fuel oil).

The cost inputs for the storage tank and the finishing reactor are summarized in Table 7.2-12.

Table 7.2-12
Process Operations Information for Additional
Units used in the Desulfurization Cost Analysis

	Diesel Storage Tank	Distillate Hydrocracker Post Treat Reactor
Capacity	50,000 bbls	25,000 (bbl/day)
Capital Cost (MM$)	0.75	5.7[18]
Electricity (KwH/bbl	—	0.98
HP Steam (Lb/bbl)	—	4.2
Fuel Gas (BTU/bbl)	—	18
Cooling Water (Gal/bbl)	—	5
Operating Cost ($/bbl)	none[a]	—

[a] No operating costs are estimated directly, however both the ISBL to OSBL factor and the capital contingency factor used for desulfurization processes is used for the tankage as well, which we believe to be excessive for storage tanks so it is presumed to cover the operating cost.

Refiners will also likely invest in a diesel fuel sulfur analyzer.[19] The availability of a sulfur analyzer at the refinery would provide essentially real-time information regarding the sulfur levels of important streams in the refinery and facilitate operational modifications to prevent excursions above the sulfur cap. Based on information from a manufacturer of such an analyzer, the cost for a diesel fuel sulfur analyzer would be about $50,000, and the installation cost would be another $5000.[20] Compared to the capital and operating cost of desulfurizing diesel fuel, the cost for this instrumentation is far below 1 percent of the total cost of this program. Because the cost is so small, the cost of an analyzer was covered as a cost contingency described in Subsection 7.2.1.4.1.

7.2.1.2.2. Sulfur Adsorption - Phillips SZorb

Phillips has developed a desulfurization technology applicable to either gasoline or diesel fuel, as discussed in some detail in Chapter 5. At our request, Phillips provided process design parameters for an SZorb diesel fuel desulfurization unit processing seven different feedstock compositions. Table 7.2-13 summarizes the information provided.[21,22]

Table 7.2-13
SZorb Process Design Parameters

Diesel Fuel Composition	Diesel A	Diesel B	Diesel C	Diesel D	Diesel E	Diesel F	Diesel G
	HT: 80% SR & 20% LCO[a]	83% SR & 17% HT LCO	SR, CKR & HT & nonHT LCO	nonHT SR	nonHT LCO	Diesel B with some non-hwy	Diesel F with HT shutdown
Feed Sulfur (ppm)	523	460	662	2000	2400	1800	3300
Product Sulfur (ppm)	6	<1	9	<1	10	6	4
LHSV (hr^{-1})	2	2	2	6	1	1.5	1
H_2 Chemical Consumption	-5	-15	15	42	186	2	90
Feed API Gravity	33	36	—	41	20	—	—
Feed 10%	440	402	—	318	480	—	—
Feed 50%	513	492	—	401	537	—	—
Feed 90%	604	573	—	496	611	—	—

[a] HT = hydrotreated, nonHT = non-hydrotreated, SR = straight run, CKR = light coker gas oil

Diesel fuels A, B and C are somewhat representative of highway diesel fuel, although the sulfur level is slightly higher than the average highway diesel fuel sulfur level found in the U.S. Diesel fuel A is a hydrotreated blend of 80 percent straight run and 20 percent LCO with distillation properties typical of today's highway diesel fuel. Diesel fuel B is a lighter blend than diesel fuel A with 83 percent unhydrotreated straight run and 17 percent hydrotreated LCO. Diesel fuel C is a rather typical diesel fuel composition for a refinery with an FCC unit and a coker. The distillation qualities of this diesel fuel, and those of diesel fuels F and G are not known.

Diesel fuels D, E, F and G have moderate sulfur levels more typical of non-highway distillate fuels. However, these fuels' sulfur contents are not as high as most refiners' unhydrotreated distillate, as discussed above. Diesel fuel D is comprised of unhydrotreated straight run with distillation qualities lighter than the average diesel fuel. Diesel fuel E is 100% unhydrotreated LCO although its relatively low sulfur level suggests that it is either from a sweet crude refinery or from a refinery with a FCC feed hydrotreater. Its distillation curve is typical of the LCO blended into the diesel fuel pool. Diesel fuel F consists of diesel fuel B plus some amount of non-highway diesel fuel. The composition of the non-highway diesel fuel is unknown. However, if we assume that the non-highway diesel fuel contains the national average sulfur level of 3400 ppm, the sulfur level of this diesel fuel blend suggests that it may be about half non-highway and half diesel fuel B. However, if the sulfur content is closer to the maximum 5000 ppm allowed under ASTM specifications, then diesel fuel F might only contain 25-30% non-highway diesel fuel. Diesel fuel G consists of diesel fuel F with the highway hydrotreater shutdown. The highway hydrotreater appears to have been only hydrotreating the LCO fraction of diesel fuel B, which represents less than 17% of Diesel fuel G. Since the sulfur content of diesel fuel G exceeds that of diesel fuel F by 1500 ppm, the sulfur content of the unhydrotreated LCO in diesel fuel B must be 9000 ppm or more, which is typical.

The design parameters provided by Phillips involve a stand-alone SZorb unit, sometimes processing unhydrotreated feedstock, and sometimes processing partially hydrotreated feedstock (i.e., following an existing conventional hydrotreater). In all cases, sulfur content is being reduced to 10 ppm or less, very close to the 7-8 ppm target which we expect refiners to have to achieve on average to comply with a 15 ppm cap. Below, we will use the process design parameters shown in Table 7.2-13 to project the cost of an SZorb unit performing two different tasks: 1) processing current high sulfur distillate to meet a 15 ppm cap, and 2) processing 500 ppm NRLM diesel fuel to meet a 15 ppm cap. The methodology used to develop the projected costs for these two tasks are presented below. As was done for conventional hydrotreating, we will develop cost estimates for processing three individual blendstocks: straight run, LCO and light coker gas oil, in order to be able to project desulfurization costs for individual refineries whose diesel fuel compositions vary dramatically.

7.2.1.2.2.1 Desulfurizing High Sulfur Distillate Fuel to Meet a 15 ppm Sulfur Cap

Phillips provided four sets of process design parameters for using SZorb to achieve a 15 ppm cap from high sulfur distillate. Two of these designs treated a pure blendstock, straight run and LCO. However, neither blendstock had properties typical of these blendstocks for the average refinery. Thus, the four sets of process designs have to evaluated together to develop sets of process design parameters for the three distillate blendstocks.

Also, the maximum initial sulfur level shown in Table 7.2-13 is 3300 ppm sulfur. Thus, we believe that it is reasonable to limit the applicability of our projections to feedstocks containing 3300 ppm sulfur or less. Current high sulfur distillate averages 3400 ppm sulfur. Therefore, it is reasonable to expect that just under half of all NRLM diesel fuel contains 3300 ppm sulfur or less.

We have broken down the derivation of the cost of a stand-alone SZorb unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: Phillips provided an estimate of hydrogen consumption for two individual blendstocks, straight run and LCO. Diesel fuel D was an unhydrotreated straight run stream hydrotreated to less than 1 ppm sulfur. Doing so consumed 42 scf/bbl of feed. Comparing its sulfur content to those for typical high sulfur distillate from Chapter 5.1, it contains 90% of the amount of sulfur in average unhydrotreated straight run. However, its distillation properties show this stream to be lighter than the average straight run feedstock. Thus, the hydrogen consumption for a more typical could be slightly higher, due to the greater concentration of aromatics typical for heavier cuts of distillate.

Interestingly, the hydrogen consumption for a number of the diesel fuel feedstocks including some LCO shown in Table 7.2-13 is less than 42 scf/bbl. A couple even show a net production of hydrogen. One of the aspects of the SZorb process is that the temperature can be varied to control the level of aromatics saturation. At low temperatures, aromatics content can actually be increased, generating hydrogen. However, there is a practical limit to this, as higher aromatic contents reduce cetane. This flexibility of the SZorb process makes it difficult to accurately predict typical hydrogen consumption, as each refiner's ability to absorb a loss in cetane will differ. Thus, to be conservative, we assumed that the 42 scf/bbl hydrogen consumption of diesel fuel D was representative of treating typical straight run.

The LCO feed (diesel fuel E) contains 2400 ppm sulfur, which is about two-thirds of the average amount of sulfur in unhydrotreated LCO, which contains 3500 ppm sulfur, as discussed in Chapter 5.1. However, it was desulfurized to a lower sulfur level than what would be expected for meeting the 500 ppm sulfur target (typically around 340 ppm). LCO usually comprises about 25 percent of diesel fuel for the average refinery with an FCC unit. LCO will likely contribute the most amount of sulfur after hydrotreating, because it generally contains largest concentration of sterically hindered sulfur compounds. Thus, to meet a 7-8 ppm sulfur target, LCO will likely need to be desulfurized to about 20 ppm and contribute about 5 ppm to the diesel fuel pool. Coker distillate might be desulfurized to roughly 5 ppm and straight run to 1-2 ppm, resulting in an average diesel fuel sulfur level of about 7 ppm. Therefore, the hydrogen consumption of 186 scf/bbl is lower than that for average LCO due to its low initial sulfur level, but is high (for a 7-8 ppm target), due to its final sulfur level of 10 ppm. Lacking the ability to compensate for either of these two factors, we assumed that the hydrogen consumption of 186 scf/bbl for diesel fuel E was representative of the hydrogen consumption for average LCO.

Phillips did not provide an estimate of the hydrogen consumption for treating 100% coker distillate. Therefore, we assumed that the relationship for hydrogen consumption for straight run, light coker distillate and LCO being treated by an SZorb unit would be the same as that for conventional hydrotreating. As described in Table 7.2-7, the hydrogen consumptions for conventionally hydrotreating straight run, coker distillate and LCO to 15 ppm are estimated to be 240, 850 and 1100 scf/bbl. Thus, for conventional hydrotreating, the hydrogen consumption for coker distillate falls 70 percent of the way between straight run and LCO. Thus, if we apply this same percentage to the straight run and LCO hydrogen consumption values for SZorb, we estimate that coker distillate would consume 144 scf/bbl of hydrogen.

An adjustment to these hydrogen consumptions was developed to account for differences in initial sulfur levels. The Phillips' feedstocks upon which the above hydrogen consumption estimates were based contain about 2100 ppm sulfur. However, as described below in subsection 7.2.1.3, the average concentration of sulfur in the overall distillate pool, and especially that part of the pool which is untreated, exceed 2100 ppm sulfur. To account for the additional hydrogen which would be consumed when processing higher sulfur feeds, we increased hydrogen consumption by 12.5 scf/bbl for each 1000 ppm of additional initial sulfur content. We did not adjust hydrogen consumption for other feedstock qualities, such as polyaromatics and olefins, because we do not believe that these would likely vary consistently with the sulfur level.

Combination with sulfur represents a significant portion of total hydrogen consumption for the Phillips process. The sulfur levels of the feeds reported by Phillips are significantly lower than the average initial sulfur levels in each PADD. Thus, the adjustments are always greater than 1.0.

For refineries with a distillate hydrotreater, the adjustment factor ranged from 1.1 for PADD 5, which has an estimated untreated distillate sulfur level of 2610 ppm, to 2.4 for PADD 3, which has an estimated untreated distillate sulfur level of 11,320 ppm. No adjustment is necessary for the already hydrotreated part of the distillate pool. This sub-pool is always assumed to contain 340 ppm sulfur, for which we use the hydrogen consumptions developed in the next section which evaluates adding SZorb unit after a hydrotreater producing 500 ppm diesel fuel.

For refineries without a distillate hydrotreater, they have no hydrotreated blendstocks, but still meet applicable sulfur limits. Thus, we estimate lower initial sulfur levels than those mentioned above. Our adjustment factors for these refineries ranged from 1.1 for PADD 5, which has an estimated initial sulfur level of 2540 ppm, to 1.5 for PADD 3 which has a initial sulfur level of 5200 ppm. The various hydrogen adjustment factors for refineries with and without a hydrotreater are summarized in the following table:

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
with Dist HT	1.6	1.5	2.4	1.3	1.1
no Dist HT	1.2	1.1	1.5	1.1	1.1

Utilities and Yield Losses: Phillips did not provide specific estimates of the utility demands for the seven designs shown in Table 7.2-13. Thus, we estimated utility demands based on a comparison of SZorb to conventional hydrotreating, guided by some general estimates provided by Phillips. The largest consumer of electricity in conventional hydrotreating is the hydrogen compressor. The SZorb process differs, in that the absorption catalyst must be recycled between the reactor and the regeneration reactor. While the SZorb process consumes much less hydrogen, it operates like conventional hydrotreating in that it requires an excess amount of hydrogen to be mixed with the diesel fuel. Thus, the total amount of hydrogen being compressed is roughly the same. However, the SZorb process operates at 275-500 psi, which is about half of the pressure at which conventional desulfurization operates. Although the SZorb process operates at about half the pressure of conventional hydrotreating and demands less hydrogen, the need to recycle catalyst likely offsets some of the savings related to hydrogen compression. Still, we estimated that the electrical demand for SZorb would be one half that of conventional hydrotreating shown in Table 7.2-7. Thus, we estimate SZorb's electricity demand to be 0.3, 0.55, and 0.6 kW-hr/bbl for straight run, light coker gas oil, and LCO, respectively.

Concerning fuel gas, it is used to heat up the feed to enable the desulfurization reaction to occur. The SZorb process operates at about the same temperature as conventional hydrotreating. Thus, we assumed that fuel gas demand would be the same as conventional hydrotreating listed in Table 7.2-7, or 60, 105, and 120 btu/bbl for straight run, light coker gas oil, and LCO, respectively.

Due to its use of adsorption, instead of hydrogenation, SZorb essentially has no yield losses.

Catalyst Costs: Conversations with Phillips indicated that the catalyst is likely to be cheaper than conventional hydrotreating catalysts. However a significant level of catalyst demand would have to occur to realize economies of scale for this lower cost to be realized. Since this process is just emerging and not many units have been licensed yet, we decided to assume the same catalyst cost as for conventional hydrotreating (shown in Table 7.2-7), or 0.3, 0.6, and 0.8 $/BPSD for straight run, light coker gas oil, and LCO, respectively.

Capital Costs: In their literature, Phillips only provides capital cost estimates for an SZorb unit processing 500 ppm sulfur diesel fuel to meet a 15 ppm sulfur cap. To be conservative[d], we assumed that the ratio of the capital costs of SZorb units treating high sulfur and 500 ppm diesel fuel to meet a 15 ppm cap, would be the same as the ratio of the capital costs of conventional hydrotreaters doing the same thing. This ratio is a factor of two for conventional hydrotreating. Phillips estimates that an SZorb unit reducing sulfur content from 500 ppm to 15 ppm would be $48 million for a 40,000 bbl/day unit, fully installed on the Gulf Coast. Thus, the cost of an SZorb unit treating the same volume of high sulfur distillate would be $96 million.

A number of steps still needed to be performed before this cost could be converted to a capital cost for processing the three individual diesel fuel blendstocks on a basis comparable to those for conventional hydrotreating above. First, we assumed that this cost included some provision for off-site costs, while the primary capital costs estimates, such as those shown in Tables 7.2-6 and 7.2-7 for conventional hydrotreating, only include "inside battery limit" (ISBL) costs. Thus, we divided the $96 million cost by a factor of 1.2 (from Table 7.2-23 below) to remove off-site costs. This produced an ISBL cost of $80 million. We then scaled this ISBL cost down to represent that for a 25,000 bbl/day unit using the "six-tenths rule with an exponent of 0.65. The scaling factor representing this reduction in volumetric capacity is 0.74 ($(25{,}000 / 40{,}000)^{0.65}$). Multiplying the $80 million cost by this factor produced a revised cost of $59 million for a 25,000 bbl/day unit.

The final step was to convert this cost for processing a mix of blendstocks to those for processing individual blendstocks. We assumed that this unit was designed to process a typical diesel fuel comprised of 69% straight run, 23% LCO and 8% other cracked stocks. We also assumed that the relationship between the capital costs for specific blendstocks (straight run, coker distillate and LCO) for SZorb was the same as those for conventional hydrotreating. Using the capital costs for conventional hydrotreating of $31, $37 and $42 million for straight run, coker distillate and LCO from Table 7.2-7, the capital cost for the above average feed

[D] The assumption is likely conservative because the SZorb desulfurization process is likely able to handle higher sulfur levels partially or perhaps even primarily by a higher rate of catalyst recycle as opposed to just increasing the unit size.

composition would be $34 million. Thus, the capital cost for an SZorb unit would be 1.7 times higher (59/34). Multiplying the capital costs for processing the individual blendstocks using conventional hydrotreating by 1.73 produced SZorb capital costs of $53, $63 and $72 million for straight run, coker distillate and LCO average.

Summary of Process Design Parameters: The process design parameters for a new, 25,000 bbl/day SZorb unit are summarized in Table 7.2-14.

Table 7.2-14
Process Design Parameters for a New SZorb Unit Desulfurizing High Sulfur Distillate Fuel to Meet a 15 ppm Cap Standard

	Straight Run	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($million)	52	63	71
Unit Size (BPSD)	25,000	25,000	25,000
Hydrogen Demand (scf/bbl)	42	144	186
Electricity Demand (kW-hr/bbl)	0.3	0.55	0.6
Fuel Gas Demand (btu/bbl)	60	105	120
Catalyst Cost ($/BPSD)	0.3	0.6	0.8
Yield Loss	0	0	0

7.2.1.2.2.2 Desulfurizing 500 ppm Diesel Fuel to Meet a 15 ppm Cap

We next estimated the process design parameters for an SZorb unit which treats distillate which has already been hydrotreated to meet a 500 ppm cap down to 7-8 ppm. We assume that this feed contains 340 ppm sulfur, the average sulfur content of highway diesel fuel today outside of California.

Phillips provided three sets of process design parameters for using SZorb to achieve a 15 ppm cap from distillate with sulfur contents just above 340 ppm (diesel fuels A, B, and C). None of these designs treated a pure blendstock. Thus, the three sets of process designs have to evaluated together to develop sets of process design parameters for the three distillate blendstocks.

As we did above, we have broken down the derivation of the cost of an SZorb unit capable of producing 15 ppm diesel fuel from 500 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: In order to estimate the hydrogen consumption for each blendstock type, we focused on diesel fuel A, which is an 80/20 blend of straight run and LCO. This fuel is the closest to the composition of average diesel fuel of diesel fuels A, B, and C shown in Table 7.2-13. Processing diesel fuel A to 6 ppm sulfur actually produces 5 scf/bbl of hydrogen. We assumed that processing straight run would produce 10 scf/bbl of hydrogen, while processing LCO would consume 15 scf/bbl. An 80/20 weighting of these two figures produces a net hydrogen production of 5 scf/bbl, precisely that for diesel fuel A. We again based the hydrogen consumption for processing coker distillate on its relative hydrogen consumption when using conventional hydrotreating. There, the hydrogen consumption to process coker distillate falls 70% of the way between those for straight run and LCO. Here, 70% of the way between -5 and +10 is +5. Thus, we assumed that the hydrogen consumption for coker distillate would be 5 scf/bbl.

Utilities and Yield Losses: As we assumed for an SZorb unit processing high sulfur distillate, we assumed that electricity demand for an SZorb unit processing 500 ppm diesel fuel would be half that for conventional hydrotreating (shown in Table 7.2-6), or 0.19, 0.34, and 0.39 kW-hr/bbl for straight run, light coker gas oil, and LCO, respectively.

Concerning fuel gas, as we assumed for an SZorb unit processing high sulfur distillate, we assumed that fuel gas demand for an SZorb unit processing 500 ppm diesel fuel would be the same catalyst cost as for conventional hydrotreating (shown in Table 7.2-6), or 38, 68, and 77 btu/bbl for straight run, light coker gas oil, and LCO, respectively.

Due to its use of adsorption, instead of hydrogenation, SZorb essentially has no yield losses.

Catalyst Costs: As we assumed for an SZorb unit processing high sulfur distillate, we assumed that the catalyst costs for an SZorb unit processing 500 ppm diesel fuel would be the same catalyst cost as for conventional hydrotreating (shown in Table 7.2-6), or 0.1, 0.2, and 0.24 $/BPSD for straight run, light coker gas oil, and LCO, respectively.

Capital Costs: As mentioned above, Phillips estimates that an SZorb unit reducing sulfur content from 500 ppm to 15 ppm would be $48 million for a 40,000 bbl/day unit installed on the Gulf Coast, including off-site costs. We divided by a factor of 1.2 to remove off-sites for a new unit (see Table 7.2-23), producing an ISBL cost of $40 million. We scaled this cost down to represent that of a 25,000 bbl/day unit using the "six-tenths rule with an exponent of 0.65. This produced a scaling factor of 0.74 and a revised ISBL cost of $29 million. As we did above, we assumed that this unit was designed to process a typical diesel fuel comprised of 69% straight run, 23% LCO and 8% other cracked stocks. We again assumed that the relationship between the capital costs for specific blendstocks (straight run, coker distillate and LCO) for SZorb was the same as those for conventional hydrotreating.

Using the capital costs for conventional hydrotreating of $15, $18 and $21 million for straight run, coker distillate and LCO from Table 7.2-7, the capital cost for the above average feed composition would be $17 million. Thus, the capital cost for an SZorb unit would be 1.7 times higher, or $27, $32 and $37 million for straight run, coker distillate and LCO average.

Summary of Process Design Parameters: The process design parameters for a new, 25,000 bbl/day SZorb unit are summarized in Table 7.2-15.

Table 7.2-15
Process Design Parameters for an SZorb Unit Desulfurizing 500 ppm
Distillate Fuel to Meet a 15 ppm Cap Standard
Blendstocks from 500 ppm to 15 ppm

	Straight Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	27	32	37
Unit Size (bbl/stream Day)	25,000	25,000	25,000
Hydrogen Demand (scf/bbl)	-10	8	15
Electricity Demand (kwh/bbl)	0.19	0.34	0.39
Fuel Gas Demand (btu/bbl)	39	68	77
Catalyst Cost ($/bpsd)	0.1	0.19	0.24
Yield Loss	0	0	0

7.2.1.2.3 Linde Isotherming

Linde has licensed a technology called IsoTherming which is designed to desulfurize both highway and non-highway distillate fuel. Upon our request, Linde provided basic design parameters for their process which could be used to project the cost of using their process to meet tighter sulfur caps.[23] Specifically, Linde provided design parameters for a revamp of an existing highway desulfurization unit to meet a 15 ppm cap standard. The revamp would put an IsoTherming unit upstream of the existing highway diesel fuel hydrotreater.

Linde provided IsoTherming designs for three revamp situations. In the first design, the feedstock consisted of 60 percent straight run and 40 percent LCO. The unhydrotreated sulfur level was just under 2000 ppm and both the existing hydrotreater and the IsoTherming unit operated at 600 psi. In the second design, the feedstock consisted of 60 percent straight run, 30 percent LCO and 10 percent light coker gas oil with an unhydrotreated sulfur level of 9950 ppm. The existing hydrotreater and the IsoTherming unit operated at 950 psi. In the third design, the feedstock was the same as in the second, but the IsoTherming unit was designed to operate at 1500 psi, while the conventional hydrotreating unit operated at 950 psi.

We based our cost projections for the IsoTherming process on the second design. The unhydrotreated sulfur level of more than 9000 ppm is more typical for most refiners than 2000 ppm. The 950 psi design pressure for the IsoTherming unit was also thought to preferable to most refiners than 1500 psi. The higher pressure unit would reduce capital and catalyst costs, but higher hydrogen consumption would offset much of the cost savings. The higher pressure reactors and compressors would also have a longer delivery time and there would likely be fewer fabricators to select from. Thus, given that the savings associated with the higher pressure unit were small, we decided to focus on the 950 psi design.

The information provided by Linde for the 950 psi IsoTherming desulfurization unit is summarized in the following table. The operation and product quality of the IsoTherming unit is shown separate from those for the existing conventional hydrotreater. Again, prior to the revamp, the conventional hydrotreater would have processed this feedstock down to roughly 300-400 ppm sulfur.

Table 7.2-16
Linde IsoTherming Revamp Design Parameters to Produce 10 ppm Sulfur Diesel Fuel

	Feed Quality	IsoTherming Unit and its Product Quality	Conventional Hydrotreater and Final Product Quality
LCO vol %	30		
Straight Run vol %	60		
Light Coker Gas Oil vol%	10		
Sulfur ppm	9950	850	10
Nitrogen	340	38	2
API gravity (degrees)	33.98	34.42	35.84
Cetane Index	44.5	48.5	50.8
H_2 Consumption (scf/bbl)		320	100
Relative H_2 Consumption		75	25
LHSV (hr^{-1})		15/15	3
Relative Catalyst Volume		45	100
Reactor Delta T		15	15
H_2 Partial Pressure		950	950
Electricity (kW)		1525	
Natural Gas (mmbtu/hr)		0	
Steam (lb/hr)		0	

7.2.1.2.3.1 Hydrotreating High Sulfur Distillate Fuel to 15 ppm

The design parameters provided by Linde involve the revamp of an existing conventional hydrotreater currently producing highway diesel fuel (i.e., less than 500 ppm sulfur) to produce diesel fuel with a sulfur level well below 15 ppm. Before addressing this situation, however, we will use the Linde revamp design to project the costs of an IsoTherming unit which processes unhydrotreated distillate fuel (e.g., 3400-10,000 ppm sulfur) down to 7-8 ppm sulfur. This type of unit was not projected to be used under the proposed two-step fuel program. However, it is projected to be used under the one-step alternative fuel program, for which costs are also estimated later in this chapter.

Also, as was done for conventional hydrotreating and the Phillips SZorb process, we will develop cost estimates for applying the IsoTherming process to three individual blendstocks, straight run, LCO and light coker gas oil, in order to be able to project desulfurization costs for individual refineries whose diesel fuel compositions vary dramatically.

We have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: In this section, we estimate the hydrogen consumption to process individual refinery streams from their uncontrolled levels down to 7-8 ppm sulfur. Linde provided hydrogen consumption estimates for desulfurizing a mixed feedstock of 60 percent straight run, 30 percent LCO and 10 percent coker distillate, but not for specific refinery streams. Additionally, Linde provided information for a hybrid desulfurization unit which is comprised of a Linde IsoTherming unit which is revamping a conventional highway hydrotreater. Upon our request for additional information, Linde informed us that the highway hydrotreater in the above described revamp is operating similar to an IsoTherming unit. Thus, we used the hydrogen consumption estimates in Tables 7.2-16 as if they represented a stand-alone IsoTherming unit.

As a first step in estimating the IsoTherming hydrogen consumption for individual blendstocks, we compared the hydrogen consumption of the Linde IsoTherming process with that of conventional hydrotreating. Table 7.2-16 shows a total hydrogen consumption of consumes 420 scf/bbl to desulfurize untreated diesel fuel to 10 ppm. Using the projected hydrogen consumption for conventional hydrotreating shown in Table 7.2-7 above, the total hydrogen consumption to desulfurize this same feedstock to 7-8 ppm would be 559 scf/bbl. Based on this example, the IsoTherming process appears to only consume 75 percent of that associated with conventional hydrotreating. Thus, we assumed that the Linde IsoTherming process would only use 71% of the hydrogen which we projected above for processing individual blendstocks using conventional hydrotreating. The resulting hydrogen consumptions were 826 scf/bbl for LCO, 638 scf/bbl for other cracked stocks, and 180 scf/bbl for straight run.

As we did for conventional hydrotreating and the Phillips SZorb process, we developed adjustments to these hydrogen consumptions to reflect differing unhydrotreated sulfur levels. We assumed that the hydrogen consumption for IsoTherming process varied in the same proportions as those for conventional hydrotreating because the treated feed sulfur levels were about the same. Thus, the same hydrogen adjustment factors were used (see subsection 7.2.1.2.1.3). The adjustment is applied as a multiplicative factor to the above base hydrogen consumption for each untreated blendstock type. For a refinery with a distillate hydrotreater, it ranged from 0.79 for PADD 5, which has an estimated untreated distillate sulfur level of 2610 ppm, to 1.08 for PADD 3 which has an estimated untreated distillate sulfur level of 11,320 ppm. No adjustment factors are applied to blendstocks which are already hydrotreated. These blendstocks are assumed to contain 340 ppm sulfur. The hydrogen consumption for the IsoTherming process when applied to diesel fuel with this initial sulfur level is described in the next Section 7.2.1.2.3.2 below.

Refineries without a distillate hydrotreater do not have any any hydrotreated blendstocks to blend into their high sulfur distillate. Thus, we estimate lower unhydrotreated sulfur levels for these refineries. The adjustment factors for these refineries ranged from 0.79 for PADD 5, which has an estimated untreated sulfur level of 2540 ppm, to 0.87 for PADD 3 which has a starting sulfur level of 5200 ppm.

Utilities and Yield Losses: We next established the IsoTherming utility inputs for individual blendstocks. The Linde IsoTherming process saves a substantial amount of heat input by conserving the heat of reaction which occurs in the IsoTherming reactors. This conserved energy is used to heat the feedstock to the unit. This differs from conventional hydrotreating which normally must reject much of this energy to avoid coking the catalyst. According to Linde, this allows the IsoTherming process to operate with essentially no external heat input. In the highway hydrotreater revamp which is the source of the information provided by Linde, the existing heater for the highway hydrotreater could essentially be turned off after the IsoTherming process was added. However, there is still the need for a small heater to heat up the feedstock during unit startup. This affects capital costs. However, when averaged over production between start-ups, this little amount of fuel used during start-up is negligible. Thus, we estimate need for either fuel or steam with the IsoTherming process.

As shown in Table 7.2-16, Linde estimated electricity demand at 1525 kilowatts. The unit was designed to process 20,000 bbl/day, so the unit electricity demand was 1.83 kilowatt-hour per barrel (kw-hr/bbl). Because the electricity demand value was not provided separately for the IsoTherming and the original conventional highway hydrotreater, we assumed that this demand applied to a stand-alone IsoTherming unit, as well. Since most of the electrical demand is due to the compression of hydrogen, and we are using the same hydrogen consumption as shown in Table 7.2-16, it is consistent that the electrical demand would be the same.

We compared this electrical demand to that of conventionally hydrotreater treating the same feedstock. Using the elecricity demands from Table 7.2-7 above, we project that the electrical demand of conventional hydrotreating would be 0.83 kW-hr/bbl. Thus, IsoTherming appears to consume 2.2 times as much electicity, probably due to increased liquid pumping associated with liquid recycle to the reactors. We assumed that this 2.2 factor applied to each individual blendstock. Thus, we estimate electricity demand at 1.3, 2.4, and 2.6 kW-hr/bbl for straight run, light coker gas oil, and LCO, respectively.

Linde did not estimate the specific yield losses for the for the IsoTherming process. Upon our request for further information, Linde indicated that their process causes slightly less than half of the yield loss of conventional hydrotreating. Thus, the yield loss of the Linde unit was projected to be 50 percent that of conventional hydrotreating which is proportional to the relative catalyst volume. The resulting projected yield losses are shown below:

	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel	0.75	1.45	1.65
Naphtha	-0.55	-1.00	-1.15
LPG	-0.03	-0.055	-0.06
Fuel Gas	-0.03	-0.085	-0.10

Catalyst Costs: The catalyst cost for the Linde process was estimated based on the relative catalyst volume compared to conventional hydrotreating. As shown in Table 7.2-16, Linde indicated that the catalyst volume for the new IsoTherming reactors contained only 45% of the volume of the new conventional hydrotreating reactors which Linde projects would have been needed to revamp the existing hydrotreater to produce 10 ppm fuel. We assumed that this same relationship would hold for a stand-alone IsoTherming unit. Thus, we multiplied the catalyst costs for conventionally hydrotreating specific blendstocks (shown in Table 7.2-7) by 45%. The resulting IsoTherming catalyst costs were 0.14, 0.27 and 0.36 $/BPSD for straight run, light coker gas oil and LCO, respectively.

Capital Costs: The last aspect of the IsoTherming process to be determined on a per-blendstock basis is its capital cost. Linde's initial submission of process design parameters did not include an estimate of the capital cost. We developed our own estimate from the process equipment included, compared to those involved in conventional hydrotreating. As indicated in Table 7.2-16, the catalyst volume of the two IsoTherming reactors unit (combined LHSV of 7.5) is roughly 8 times smaller than that of a conventional hydrotreating revamp (LHSV of 0.9 per LHSVs for individul blenedstocks from Table 7.2-6). Also, because the IsoTherming reactors use a much higher flowrate and is a totally liquid process (no need for both gas and liquid in the reactor), it eliminates the need for an expensive distributor. As mentioned above, the feed pre-heater can be much smaller and less durable, since it is only required for startup. Finally, the IsoTherming process does not require an amine scrubber to scrub the H_2S from the recycle hydrogen stream.

Based on these differences, we estimated that the total capital cost of a stand-alone IsoTherming unit would be two-thirds that for a conventional hydrotreater. Thus, the capital costs for a 25,000 bbl per day conventional hydrotreater were reduced by one-third. The resulting IsoTherming capital costs for a 25,000 BPSD unit were $21, $25, and $29 million for treating straight run, light coker gas oil and LCO, respectively. The overall capital cost for the specific feed composition shown in Table 7.2-16 above would be $900 per BPSD for the IsoTherming unit, versus $1400 per BPSD for a conventional hydrotreater. More recently, Linde indicated that the capital cost would be roughly $800 per barrel for a 25,000 bbl per day unit.[24] For this analysis, we retained the two-thirds factor relative to conventional hydrotreating ($900 per BPSD). We are considering reducing this cost by 11% to match that of the most recent Linde estimate for our analyses following the proposed rule.

Summary of Process Design Parameters: Table 7.2-17 summarizes the design parameters used for using the Linde IsoTherming process to desulfurize untreated distillate fuel to 10 ppm.

Table 7.2-17
Process Parameters for a Stand-Alone IsoTherming 25,000 BPSD Unit to Produce 10 ppm Sulfur Fuel from Untreated Distillate Fuel

	Straight Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	21	25	29
Hydrogen Demand (scf/bbl)	187	663	858
Electricity Demand (kwh/bbl)	1.71	3.10	3.41
Fuel Gas Demand (btu/bbl)	0	0	0
Catalyst Cost ($/bpsd)	0.16	0.31	0.46
Yield Loss (wt%): Diesel	0.75	1.45	1.65
Naphtha	-0.55	-1.00	-1.10
LPG	-0.03	-0.055	-0.06
Fuel Gas	-0.03	-0.085	-0.10

7.2.1.2.3.2 Desulfurizing 500 ppm Sulfur Diesel Fuel to Meet a 15 ppm Sulfur Cap

The derivation of process design parameters for a IsoTherming unit revamp of a conventional hydrotreater is much more straightforward than that of a stand-alone IsoTherming unit, as the design parameters provided by Linde in Table 7.2-16 were for a revamp. As above, we have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: Table 7.2-16 depicts the hydrogen consumption for an IsoTherming revamp, but does not provide the hydrogen consumption for the original highway hydrotreater. In estimating hydrogen consumption for a stand-alone IsoTherming unit above, we estimated that the hydrogen consumption for a conventional hydrotreater processing that feedstock to 10 ppm sulfur would consume 559 scf/bbl. The IsoTherming revamp is projected to consumes only 420 scf/bbl, for a savings of 139 scf/bbl. Using the hydrogen consumptions shown in Table 7.2-6, a conventional hydrotreating revamp is projected to consume 193 scf/bbl of hydrogen over that being consumed in the original highway fuel hydrotreater. Thus, the IsoTherming process appears to reduce this incremental consumption by 71% (139/193 * 100%). Given that we had to project the hydrogen consumption of the original hydrotreater, we decided to only project a 60% savings for an IsoTherming revamp, rather than 71%. We will review this estimate for future analyses as additional data from the IsoTherming revamp being installed at a Giant refinery becomes available. Reducing the hydrogen consumptions shown in Table 7.2-6 by 60%, the resulting hydrogen consumptions for an IsoTherming revamp were 150 scf/bbl for LCO, 92 scf/bbl for other cracked stocks, and 38 scf/bbl for straight run.

Utilities and Yield Losses: We followed the same methodology for estimating electricity demand as we did above for hydrogen consumption. We estimated above that the electricity demand for a conventional hydrotreater processing that feedstock to 10 ppm sulfur would consume 0.83 kW-hr/bbl. The IsoTherming revamp is projected to consume 1.83 kW-hr/bbl, an increase of 1.0 kW-hr/bbl. Using the electricity demand shown in Table 7.2-6, a conventional hydrotreating revamp is projected to use 0.53 kW-hr/bbl of electricity over that being used in the original highway fuel hydrotreater. Thus, the IsoTherming process appears to increase this incremental usage by 190% ((1.53/0.53 - 1) * 100%). Given that we had to project the electricity demand of the original hydrotreater, we decided to project a slight larger increase of 225% for an IsoTherming revamp, rather than 190%. We will review this estimate for future analyses as additional data from the IsoTherming revamp being installed at a Giant refinery becomes available. Increasing the electricity demand shown in Table 7.2-6 by 225%, the resulting electricity demand for an IsoTherming revamp were 2.6 kW-hr/bbl for LCO, 2.3 kW-hr/bbl for other cracked stocks, and 1.3 kW-hr/bbl for straight run.

Regarding fuel gas consumption, the total fuel gas consumption for a stand-alone IsoTherming unit was projected above to be zero, due the enhanced ability to conserve heat generated in the aromatic saturation reactions which accompany desulfurization. The process projections shown in Table 7.2-16 above show no consumption of natural gas by the unit. Thus, it would seem reasonable to project that a Linde revamp would cause no increase in fuel gas consumption. In fact, if the total use of natural gas was zero, one might expect that the IsoTherming revamp actually reduced fuel gas consumption, as the original hydrotreater would have been consuming some fuel gas. However, to be conservative, we projected that a IsoTherming revamp would require the same fuel gas consumption as that of a conventional hydrotreating revamp. We will review this estimate for future analyses as additional data from the IsoTherming revamp being installed at a Giant refinery becomes available.

As mentioned above, Linde did not provide estimates of yield losses for the IsoTherming process. We estimated that a stand-alone IsoTherming unit would reduce yield losses by 45% compared to a stand-alone convention hydrotreater. Table 7.2-6 shows that the yield loss for straight run feed is 1.0% for a conventional hydrotreating revamp and Table 7.2-7 shows a 1.5% loss for a grass roots conventional hydrotreater. Thus, the yield losses for a conventional hydrotreating revamp is two-thirds of the yield loss for a grass roots conventional hydrotreater. Thus, the original highway fuel hydrotreater has a yield loss of 0.5% for straight run, consistent with that shown in Table 7.2-11.

If the IsoTherming revamp reduces the yield loss by 45%, its yield loss for straight run is 55% of 1.5%, or 0.82%. Subtracting out the 0.5% loss of the original highway hydrotreater means that the IsoTherming revamp had an incremental yield loss of 0.32%, or 32% of the 1.0% yield loss projected for the conventional hydrotreating revamp. Thus, we projected that all of the yield losses shown in Table 7.2-6 for a conventional hydrotreating revamp would be only 32% as large for an IsoTherming revamp.

	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel	0.32	0.61	0.70
Naphtha	-0.22	-0.42	-0.48
LPG	-0.01	-0.02	-0.03
Fuel Gas	-0.01	-0.035	-0.04

Catalyst Costs: Consistent with the relative catalyst cost for a stand-alone IsoTherming unit, we project that the catalyst cost for an IsoTherming revamp would be 45% of that for a conventional hydrotreating revamp.

Capital Costs: Consistent with the relative capital cost for a stand-alone IsoTherming unit, we project that the capital cost for an IsoTherming revamp would be 45% of that for a conventional hydrotreating revamp.

Summary of Process Design Parameters: The inputs into our cost model for treating already treated non-highway diesel fuel by the individual refinery streams which is presumed to be 340 ppm is summarized in the following table.

Table 7.2-18
Process Projections for an IsoTherming Revamp of a Conventional Hydrotreater to Meet a 15 ppm Cap Standard

	Straight Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	10.6	12.5	14.5
Unit Size (bbl/stream Day)	25,000	25,000	25,000
Hydrogen Demand (scf/bbl)	38	92	150
Electricity Demand (kwh/bbl)	1.30	2.28	2.60
Fuel Gas Demand (btu/bbl)	0	0	0
Catalyst Cost ($/bpsd)	0.09	0.17	0.22
Yield Loss (wt%)			
Diesel	0.25	0.48	0.55
Naphtha	-0.18	-0.33	-0.38
LPG	-0.01	-0.02	-0.02
Fuel Gas	-0.01	-0.03	-0.03

7.2.1.2.4 Characterization of Vendor Cost Estimates

Applicability to Specific Refineries: The information provided by the vendors is based on typical diesel fuels or diesel fuel blendstocks. However, in reality, diesel fuel (especially LCO, and to a lesser degree other cracked stocks) varies in desulfurization difficulty based on the amount of sterically hindered compounds present in the fuel, which is determined by the endpoint of diesel fuel, and also by the type of crude oil being refined and other unit processes.

The vendors provided cost information based on diesel fuels with T-90 distillation points which varied from 605 ˚F to 630 ˚F, which would roughly correspond to distillation endpoints of 655 ˚F to 680 ˚F. These endpoints can be interpreted to mean that the diesel fuel would, as explained in Chapter V above, contain sterically hindered compounds. Other diesel fuels or diesel fuel blendstocks, such as the straight run diesel fuel in the SZorb estimates, are lighter and would not contain sterically hindered compounds. However, a summer time diesel fuel survey for 1997 shows that the endpoint of highway diesel fuel varies from 600 ˚F to 700 ˚F, thus the lighter diesel fuels would contain no sterically hindered compounds, and the heavier diesel fuels would contain more.[25] Our analysis attempts to capture the cost for each refinery to produce highway diesel fuel which meets the 15ppm cap sulfur standard, however, we do not have specific information for how the highway diesel endpoints vary from refinery to refinery, or from season to season. Similarly, we do not have information on what type of crude oil is being processed by each refinery as the quality of crude oil being processed by a refinery affects the desulfurization difficulty of the various diesel fuel blendstocks. Diesel fuel processed by a particular refiner can either be easier or more difficult to treat than what we estimate depending on how their diesel fuel endpoint compares to the average endpoint of the industry, and depending on the crude oil used. For a nationwide analysis, it is appropriate to base our cost analysis for each refinery on what we estimate would be typical or average qualities for each diesel fuel blendstock. Some estimates of individual refinery costs will be high, others will be low, but be representative on average.

Accuracy of Vendor Estimates: We have heard from refiners in the past that the vendor costs are optimistic and need to be adjusted higher to better assess the costs. While the vendors costs may be optimistic, we believe that there are a multitude of reasons why the cost estimates should be optimistic.

First, in specific situations, capital costs can be lower than what the vendors project for a generic refinery. Many refiners own used reactors, compressors, and other vessels which can be employed in a new or revamped diesel hydrotreating unit. We do not know to what extent that additional hydrotreating capacity can be met by employing used vessels, however, we believe that at least a portion of the capital costs can be offset by used equipment.

There are also operational changes which refiners can make to reduce the difficulty and the cost of desulfurizing highway diesel fuel. Based on the information which we received from vendors and as made apparent in our cost analysis which follows, refiners with LCO in their diesel fuel would need to hydrotreat their highway diesel pool more severely resulting in a higher cost to meet the cap standard. We believe that these refiners could potentially avoid some or much of this higher cost by pursuing two specific options. The first option which we believe these refiners would consider would be to shift LCO to heating oil which does not face such stringent sulfur control . The more lenient sulfur limits which regulate heating oil provide room for blending in substantial amounts of LCO. The refineries which could take advantage of shifting LCO to the heating oil pool are those in the Northeast and on the Gulf Coast which have access to the large heating oil market in the Northeast. Another option is for refiners to shift some of their LCO to the locomotive and marine markets. While these markets would be regulated to a 500 ppm sulfur standard, it is less stringent and does not require the aggressive desulfurization of the sterically hindered compounds. Because of the low cetane value inherent with LCO, refiners cannot simply dump a large amount into locomotive and marine diesel since those two pools must meet an ASTM cetane specification. Thus, we believe that refiners could distill its LCO into a light and heavy fraction and only shift the heavy fraction to off-highway, locomotive, and marine diesel fuels. Essentially all of the sterically hindered compounds distill above 630 ^{o}F, so if refiners undercut their LCO to omit these compounds, they would cut out about 30 percent of their LCO. We expect that refiners could shift the same volume of non-LCO distillate from these other distillate pools to the non-highway pool to maintain current production volumes of all fuels. In addition to the cetane limit which restricts blending of LCO into non-highway diesel, the T-90 maximum established by ASTM limits would limit the amount of LCO, and especially heavy LCO, which can be moved from nonroad diesel fuel into these other distillate streams. The exception, of course, would be to move this dirty distillate fraction into number 4 or number 6 marine bunker fuel. For those refineries which could trade the heavy portion of LCO with other blendstocks in the high sulfur pool from own refinery or other refineries, we presume that those refiners could make the separations cheaply by using a splitting column for separating the undercut LCO from the uncracked heavy gasoil in the FCC bottoms.

Another option for refineries which are faced with treating LCO in its nonroad diesel fuel would be to sell off or trade their heavy LCO to refineries with a distillate hydrocracker. This is a viable option only for those refineries which are located close to another refinery with a distillate hydrocracker. The refinery with the distillate hydrocracker would upgrade the purchased LCO into gasoline or high quality diesel fuel. To allow this option, there must be a way to transfer the heavy LCO from the refinery with the unwanted LCO to the refinery with the hydrocracker, such as a pipeline or some form of water transport. We asked a refinery consultant to review this option. The refinery consultant corroborated the idea, but commented that the trading of blendstocks between refineries is a complicated business matter which is not practiced much outside the Gulf Coast, and that the refineries with hydrocrackers that would buy up and process this low quality LCO may have to modify their distillate hydrocrackers.[26] The modification which may be needed would be due to the more exothermic reaction temperature of treating LCO which could require refiners to install additional quenching in those hydrocrackers. Additionally, LCO can demand 60 to 80 percent more hydrogen for processing than straight run material. The refineries which could potentially take advantage of selling or trading their LCO to these other refineries are mostly located in the Gulf Coast where a significant number of refineries have hydrocrackers and such trading of blendstocks is common. However, there are other refineries outside the Gulf Coast which could take advantage of their very close location to another refinery with a distillate hydrocracker. Examples for these refining areas where a hydrocracker could be shared include the Billings, Montana area and Ferndale, Washington.

As we summarized in Chapter 5, catalysts are improving and expected to continue to improve. Our costs are based on vendor submissions and incorporate the most advanced catalysts available. As catalysts continue to improve, the cost of desulfurizing diesel fuel will continue to decrease.

In summary, if the vendor cost estimates are optimistically low, there are a number of reasons why the cost of desulfurizing highway diesel fuel to meet the 15 ppm cap standard are likely to be low. Vendors are expected to continue to improve their desulfurization technology such as the activity of their catalysts. Also, refiners have several cost cutting options at their disposal such as using existing spare equipment to lower their capital costs. Also, refiners may be able to resort to either of two operational options to reduce the amount of LCO in their highway diesel fuel.

We are aware that there are potentially other capital and operating costs in the refinery which would contribute the projected cost of desulfurizing diesel fuel beyond that provided to us by the vendors. For example, refiners may need to expand their amine plant or their sulfur plant to enable the processing of the sulfur compounds removed from diesel fuel. Then the small amount of additional sulfur compounds treated would incur additional operating costs. Thus, as described below, we adjusted the projected capital and operating costs upward to account for these other potential costs which we have not accounted for explicitly.

7.2.1.3 Composition of Distillate Fuel by Refinery

In the previous section, we established distinct desulfurization costs for the various blendstocks comprising diesel fuel. To apply these costs to each refinery, we must estimate the each refinery's diesel fuel composition. Refiners do not publish this information, so we estimated these compositions from other publically available sources of information. The fraction of LCO in distillate fuel is addressed first, then we estimate the fraction of other cracked stocks and lastly, the fraction of hydrocrackated stocks. By estimating the fractions of each refinery's number two distillate comprised by these various blendstocks, the remaining fraction is comprised of straight run distillate. In addition to these primary sources of distillate blendstocks, the fraction of distillate currently being hydrotreated also affects the cost of further sulfur control, particularly the required consumption of hydrogen. Thus, the fraction of distillate fuel which is currently hydrotreated is also estimated below for each refinery. Finally, how distillate composition might be changing over time is discussed.

Light-Cycle Oil: First, we estimated the volume of LCO produced by each refinery based on the capacity of its Fluidized Cat Cracker unit (FCC unit). The Oil and Gas Journal (OGJ) publishes information on the capacity of major processing units for each refinery in the country, including the FCC unit.[27] Based on the results of API/NPRA's Refining Operations and Product Quality survey, the FCC units typically operate at 90 percent of capacity.[28] The API/NPRA survey also shows that number two distillate produced nationally (outside of California) contains 21 percent LCO averaged over the entire pool. However before using this information for estimating the amount of FCC feed which is produced as LCO for each refinery, we needed to take two important steps to facilitate the calculation. First, it was necessary to account for the LCO which is processed by the hydrocracker in the refinery. As discussed above, refineries with hydrocrackers normally send their LCO to the hydrocracker and convert most of it to gasoline. Thus, for refineries with distillate hydrocrackers, we reduced their estimated LCO production by the operational capacity of their hydrocracker (again estimated to be 90% of rated capacity per the above API/NPRA survey). Also, an FCC feed hydrotreater can significantly improve the quality of LCO. However, we do not believe that refineries outside of California[e] have FCC feed hydrotreaters with sufficiently high hydrogen pressure to produce this quality improvement. Also, we do not have a source of desulfurization costs for LCO produced from an FCC unit with feed pretreatment versus more typical LCO. Thus, all LCO was assumed to have the same quality.

Second, EIA regularly collects data from refiners, including their production volumes of high and low sulfur distillate fuel. According to EIA, 138 U.S. refiners produced a total of 55 billion gallons of distillate in 2000, with 17 billion gallons (about 31 percent) being high sulfur diesel fuel produced by 105 refineries. The 1996 API/NPRA survey shows that the LCO fraction of low sulfur and high sulfur distillate fuel are quite similar. Therefore, for the purpose of estimating the fraction of each refinery's feed to the FCC unit which is produced as LCO, of we assumed that the LCO fraction of each refinery's low and high sulfur distillate fuel were equal.

We then backcalculated from the aggregate figure that 21 percent of the nation's refineries' number 2 distillate is LCO, and based on the premise that refineries with hydrocrackers processed their LCO in that unit, that refineries with FCC units produce 25 percent LCO from the feed to those units. We then categorized the 105 refineries producing high sulfur distillate based on the LCO fraction of their distillate pool at 5 or 10 percent intervals from 0 to 60 percent. The distribution of refineries by fraction of LCO is summarized in Table 7.2-19.

[E] This analysis does not model the Federal nonroad standards applying in California since it is expected that California will be implementing its own program before the Federal program takes effect.

Table 7.2-19
Distribution of LCO in Distillate Fuel by Refinery
(High Sulfur Producing U.S. Refineries)

	Percentage of LCO in the Distillate Pool							
	0%	<10%	<20%	<25%	<30%	<40%	<50%	<80%
Number of Refineries	44	45	51	61	81	96	101	104
Cumulative Percentage of US Nonroad Diesel Volume	26	27	34	52	74	87	97	99

As the table shows, we estimate that distillate fuel produced by refineries which produce high sulfur distillate contains anywhere from zero LCO to over 80 percent LCO. The table also shows that 44 U.S. refineries, which produce about 26 percent of the high sulfur distillate in the U.S., blend no LCO into their distillate. The above table also reveals that the distillate from the remaining 61 refineries averages about 28 percent LCO by volume.

Other Cracked Stocks: In addition to LCO, nonroad diesel fuel is comprised of other cracked stocks such as light coker gas oil, light visbreaker gas oil, and light thermally cracked gas oil. These other cracked stocks are somewhat more difficult to treat than straight run distillate, but less difficult to treat than LCO. Light coker gas oil dominates this intermediate group of blendstocks and we have estimates available for its desulfurization costs. Therefore, we estimated the fraction of all of these other cracked stocks in each refinery's high sulfur distillate fuel and treat the volume as light coker gas oil for cost estimation purposes.

Similar to our approach for LCO, we based the volume of each of these cracked stocks on the capacity of the refining units which produce them, namely delayed and fluid cokers, visbreakers, and thermal crackers. Based on the above mentioned API/NPRA survey, we estimate that all of these units operate at 90 percent of capacity. Based on confidential estimates from a refining industry consultant, we estimate that 30 percent of delayed coker and 15 percent of the other units' production is distillate blended into the distillate pool. As we did with our procedure for LCO, refineries with hydrocrackers were assumed to send these other cracked stocks to the hydrocracker for conversion to gasoline to the extent that capacity remained after any LCO was processed by that unit. We also again spread the volume of these other cracked stocks proportionately across each refinery's production of low and high sulfur distillate fuel based on the information in the API/NPRA survey [29] which shows that the other cracked stocks is fairly well equally distributed across these two pools.

Summing the volume of other cracked stocks in high distillate across all refineries, we found that about 8 percent of the entire distillate fuel volume produced by high sulfur distillate producing refineries is comprised of these other cracked stocks. This value agrees well with the 1996 API/NPRA survey of distillate fuel. The fractions which cracked stocks comprise of the total distillate pool for refineries which produce high sulfur distillate fuel was characterized for the industry as a whole and summarized below in Table 7.2-20.

Table 7.2-20
Distribution of Other Cracked Stocks in Distillate Fuel by Refinery
(High Sulfur Producing U.S. Refineries)

	Percentage of Other Cracked Stocks in the Distillate Pool						
	0%	<10%	<15%	<20%	<25%	<30%	<40%
Number of Refineries	74	76	86	94	97	102	105
Cumulative Percentage of US non-Highway Diesel Volume	48	51	64	76	78	96	100

As shown, we estimate that almost half of distillate fuel in the U.S, which is produced by 74 refineries, does not contain other cracked stocks from cokers, visbreakers and thermal crackers. Of the refineries which are projected to blend other cracked stocks into their distillate pool, the analysis predicts that, on average, the distillate fuel from these refineries contains approximately 19 percent of other cracked stocks.

Hydrocracked: In the U.S., hydrocrackers are almost exclusively used to crack undesirable distillate blendstocks, primarily LCO, into more desirable products, such as gasoline. However, not all of this distillate material is converted to gasoline. The portion which remains distillate is of high quality.[f] We again obtained the hydrocracker capacity by refinery from the OGJ. The 1996 API/NPRA survey of distillate fuel composition indicated that 5.8 percent of all distillate was hydrocracked. Dividing 5.8% of total distillate production in 2000 by total hydrocracker capacity, we found that about 20 percent of the hydrocracker capacity is hydrocracked distillate, which is also termed hydrocrackate. This percentage was assumed to apply to all hydrocrackers.

Unlike the other blendstocks, the 1996 API/NPRA survey indicated that hydrocrackate comprises a smaller percentage of low sulfur diesel fuel (4.4%) than high sulfur distillate fuel (8.8%). Thus, for refineries which produced both low and high sulfur distillate fuel in 2000, we allocated a higher percentage of hydrocrackate to their high sulfur pool than their low sulfur pool until the overall percentage of hydrocrackate in low and high sulfur distillate fuel pools equaled 4.4 percent and 8.8 percent, respectively.

Hydrotreated Material in High Sulfur Distillate: The 1996 API/NPRA fuel quality survey shows that a significant percentage of the blendstocks comprising high sulfur distillate are

[F] According to Mathpro, hydrocracked distillate is high in cetane (~46) and low in sulfur (~100 ppm) relative to the feedstock which if it is LCO is low in cetane (~25) and high in sulfur (~12,000 ppm) hydrotreated, despite the fact that the final sulfur level is 2000 ppm or more. This is likely necessary to improve the stability of untreated LCO, as well as meet applicable cetane and sulfur specifications with blendstocks which can exceed 10,000 ppm sulfur and have a cetane number of less than 15 prior to hydrotreating. The fact that a portion of high sulfur distillate fuel is currently hydrotreated is important, because this removes all of the olefins and saturates some of the aromatics, reducing subsequent hydrotreating costs. While hydrotreating also removes some of the sulfur from these streams, our estimates of the amounts of sulfur in high sulfur distillate come from measurements of finished high sulfur distillate. Thus, while hydrotreated blendstocks have reduced sulfur levels, this means that the unhydrotreated blendstocks have higher sulfur levels, which combined, produce the final, surveyed sulfur level. The API/NPRA survey shows that the fraction of the high sulfur distillate pool which is desulfurized varies significantly between PADDs. Thus, the refinery model was calibrated against the 1996 API/NPRA Refinery Survey at the PADD level instead of at the national level. Table 7.2-21 summarizes the fraction of high sulfur distillate which is hydrotreated in each PADD.

Table 7.2-21
Hydrotreated Percentage of High Sulfur Distillate Blendstocks

PADD	Percent Hydrotreated
1	27
2	31
3	44
4	17
5 (CA excluded)	2
AK	0

As Table 7.2-3 shows, PADD 3 has the highest percentage of its high sulfur distillate pool hydrotreated at 44 percent. None of Alaska’s fuel is believed to be hydrotreated since none of the refineries located in Alaska have distillate hydrotreaters.

The hydrotreated blendstocks of the high sulfur distillate pool are assumed to be treated to meet the current highway sulfur standard average of 340 ppm. We believe that this is reasonable because many refiners who are blending their nonroad diesel fuel using both hydrotreated and unhydrotreated streams likely only have a single hydrotreater and they are simply blending some of their highway diesel fuel with high sulfur distillate to produce a product which meets either nonroad or heating oil standards. There could be refiners who have dedicated hydrotreaters in their refineries for treating high sulfur distillate for producing nonroad or heating oil directly, or for blending with other high sulfur distillate for producing nonroad or heating oil. Thus the hydrotreated product could be higher or lower than the current average of 340 ppm. However, as seen below, this would simply result in a lower or higher starting sulfur level for the balance of the pool which is not desulfurized and the net desulfurization cost would be about the same. Also, one cannot tell by looking at the U.S. refinery unit capacities in the Oil and Gas Journal if there is dedicated nonroad distillate hydrotreating capacity or not. Assigning the hydrotreated stocks a sulfur level of 340 ppm simplifies the analysis.

As seen in Section 7.1, average sulfur levels were calculated for each PADD. Using these as a starting point, PADD-specific starting sulfur levels were estimated for each PADD depending on whether the refinery had a distillate hydrotreater or not. If a refinery did not have a distillate hydrotreater, then its starting sulfur level is the same as that reported in Section 7.1. However, if the refinery did have a diesel hydrotreater, then the sulfur level for the unhydrotreated portion of the nonroad pool was calculated. One adjustment was made to the average starting sulfur levels of PADDs 1 and 3. Because the high sulfur producing refineries in those two PADDs have hydrocrackers, the sulfur levels were adjusted to estimate the sulfur level of the nonhydrocracked blendstocks. Excluding hydrocracked distillate from the average sulfur level is important as hydrocracked distillate is not expected to be treated in new distillate hydrotreater equipment added to comply with the 500 ppm and 15 ppm sulfur cap standards. The various sulfur levels are summarized in Table 7.2-22 and these are used to estimate the cost of desulfurizing nonroad diesel fuel.

Table 7.2-22
High Sulfur Distillate Fuel Sulfur Levels[a]
(Excludes Hydrocracked Blendstocks)

PADD	Sulfur Level of High Sulfur Distillate in Refineries without Hydrotreaters	Sulfur Level of Hydroteated Blendstocks in Refineries with Distillate Hydrotreaters	Sulfur Level of non-Hydrotreated High Sulfur Distillate in Refineries with Distillate Hydrotreaters
1	3420	340	6130
2	3000	340	5400
3	5200	340	11,320
4	2700	340	4200
5 (Excluding CA)	2540	340	2600
Alaska	2540	—	2540

[a] The values in the third column are calculated from the sulfur levels of the first column, the sulfur levels of the second column and the percentages in Table 7.3-3

Trends in Distillate Fuel Composition: It is likely that refiners will want to shift their blendstocks in an effort to reduce their costs for complying with the 15 ppm highway diesel fuel standard in 2006. Directionally, refiners would likely shift their more difficult to treat blendstocks (LCO and other cracked stocks) to high sulfur distillate and their easier to treat blendstocks (straight run and hydrocrackate) to highway fuel. Heating oil must meet at least the 5000 ppm sulfur specification, as well as more stringent state specifications, as low as 2000 ppm. Most high sulfur diesel fuel and heating oil is shipped as a single fuel, so high sulfur diesel fuel often must meet state sulfur standards for heating oil and heating oil must have a cetane number of at least 40. However, nonroad diesel fuel must continue to meet a 40 cetane specification and a 500 ppm sulfur specification. Since straight run and hydrocrackate generally have higher cetane levels and lower sulfur levels than the other blendstocks, only a limited amount of such shifting is feasible.

The sulfur content and cetane number of each type of blendstock can vary widely depending on the specific crude oil processed and the design of the refining equipment employed. Therefore, estimating the degree to which each refinery could shift its blendstocks around to minimize its desulfurization costs under the highway diesel fuel rule was not possible. However, in an attempt to partially reflect shifting that could occur, we shifted some hydrocrackate from selected refineries' high sulfur distillate pool to their low sulfur pool. This was only done when a blendstock with relatively high cetane and low sulfur was available to replace the hydrocrackate. The only blendstock considered to be of sufficiently high quality to replace hydrocrackate was distillate which had been processed through a distillate hydrotreater. Once hydrotreated, typically blended distillate tends to have reasonable cetane and sulfur levels, so the specific composition of the hydrotreated distillate is not critical. Thus, only those refineries with both hydrocrackers and distillate hydrotreaters were assumed to move the hydrocracked distillate over to the highway pool. The composition of the hydrotreated distillate shifted to the high sulfur distillate fuel pool was assumed to match the composition of all the non-hydrocracked distillate material produced by the refinery. Since the majority of current low sulfur diesel fuel is hydrotreated to meet the 500 ppm cap, plenty of hydrotreated material was usually available for swapping for the hydrocracked distillate available from the high sulfur distillate pool. Thus, most of the hydrocrackate from refineries producing both low and high sulfur distillate in 2000 was shifted to the low sulfur fuel pool. After this shift, hydrocracked distillate comprised 2.6 percent of the high sulfur distillate pool and 7.2 percent of the highway diesel pool.

The distillate fuel compositions estimated above are based primarily on data from the 1996 API/NPRA survey and current refinery unit capacities. We assumed that these compositions would remain constant throughout the timeframe of the analysis: 2007-2030. A recent presentation by EIA indicates that this is not likely to be the case. While the volumes of light and medium crude oils processed by U.S. refineries has been relatively constant over the past 15 years, the volume of heavy crude oils has increased significantly. This has lead to an increase in the fraction of crude oil volume processed through conversion units, particularly cokers and hydrocrackers. FCC unit capacity also increased slightly as a fraction of total crude oil distillation capacity Thus, the 1996 API/NPRA distillate fuel quality survey likely underestimates the amount of other cracked stocks and hydrocracked material in distillate fuel. While this analysis does not reflect this trend, we plan to incorporate this trend into future estimates of the cost of desulfurizing diesel fuel.

7.2.1.4 Summary of Cost Estimation Factors

This section presents a number of costs, such as those for electricity and natural gas, as well as cost adjustment factors which are applicable to all three of the above desulfurization technologies.

7.2.1.4.1 Capital Cost Adjustment Factors

Unit Capacity: The capital costs supplied by the vendors of desulfurization technologies apply to a particular volumetric capacity. We adjust these costs to represent units with lower or higher volumetric capacity using the "sixth tenths rule."[g] According to this rule, commonly used in the refining industry, the capital cost of a piece of equipment varies in proportion to the ratio of the new capacity to the base capacity taken to some power, typically 0.6. This allows us to estimate how the capital cost might vary between refineries due to often large differences in the amount of distillate fuel which they are desulfurizing.

Stream Day Basis: The EIA data for the production of distillate by various refineries is on a calendar basis. In other words, it is simply the annual distillate production volume of the period of interest divided by the number of days in the period. However, refining units are designed on a stream day basis. A stream day is a calendar day during which the unit is actually or expected to be operational. Refining units must be able to process more than the average daily throughput due to changes in day-to-day operations, to be able to handle seasonal difference in diesel fuel production and to be able to re-treat off-specification batches. The capital costs for the three desulfurization technologies were provided on a stream day basis.

Actual refining units often operate 90 percent of the time, or in other words, can process 90% of their design capacity over the period of a year. However, when designing a new unit, it is typical to assume a lower operational percentage. We have assumed that a desulfurization unit would be designed to meet its annual production target while operating only 80% of the time. This means that the unit capacity in terms of stream days must be 20 percent greater than the required calendar day production.

Off-site and Construction Location Costs: The capital costs provided by vendors do not include off-site costs, such as piping, tankage, wastewater treatment, etc. They also generally assume construction on the Gulf Coast, which are the lowest in the nation. Off-site costs are typically assumed to be a set percentage of the on-site costs.

The off-site cost factors and construction location cost factors used in this analysis were taken from Gary and Handewerk.[30] The offsite factors provided by Gary and Handewerk apply to a new desulfurization unit. Off-site costs are much lower for a revamped unit, as the existing unit is already connected to the other units of the refinery, utilities, etc.. Thus, we reduced the off-site factors for revamped units by 50%.[31]

[G] The capital cost is estimated at this other throughput using an exponential equation termed the "six-tenths rule." The equation is as follows: $(Sb/Sa)^e xCa=Cb$, where Sa is the size of unit quoted by the vendor, Sb is the size of the unit for which the cost is desired, e is the exponent, Ca is the cost of the unit quoted by the vendor, and Cb is the desired cost for the different sized unit. The exponential value "e" used in this equation is 0.9 for splitters and 0.65 for desulfurization units (Peters and Timmerhaus, 1991).

The off-site factors vary by refinery capacity, while the construction location factors vary between regions of the country.[32] In our analysis of the costs for the Tier 2 gasoline sulfur rule, we estimated the average of each factor for each PADD. There, all the naphtha desulfurization units were new units. Thus, the PADD-average off-site factors developed for that rule were simply divided by two to estimate PADD-average factors for revamped units here. The resulting factors are summarized in Table 7.2-23.

Table 7.2-23
Offsite and Construction Location Factors

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Offsite Factor					
- New Unit	1.26	1.26	1.20	1.30	1.30
- Revamped Unit	1.13	1.13	1.10	1.15	1.15
Construction Location Factor	1.5	1.3	1	1.4	1.2

Additional Capital Costs: There are also likely some capital costs associated with equipment not included in either the vendor's estimates, nor the general off-sites. Examples would be expansions of the amine and sulfur plants to address the additional sulfur removed, a new sulfur analyzer. To account for these other capital costs, and for other contingencies, capital costs (including off-sites) were increased by 15 percent, typical for this type of analysis.[33] In addition, we increased this factor to 18% to include the costs of starting up a new unit.[34]

Capital Amortization: The economic assumptions used to amortize capital costs over production volume and the resultant capital amortization factors are summarized below in Table 7.2-24.[35] These inputs to the capital amortization equation are used in the following section on the cost of desulfurizing diesel fuel to convert the capital cost to an equivalent per-gallon cost.[h]

Table 7.2-24
Economic Cost Factors Used in Calculating the Capital Amortization Factor

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0 %	7%	0.11
Capital Payback	10 Years	15 Years	39 %	6% 10%	0.12 0.16

[H] The capital amortization factor is applied to a one time capital cost to create an amortized annual capital cost which occurs each and every year for the 15 years of the economic and project life of the unit. This implicitly assumes that refiners would reinvest in desulfurization capacity after 15 years at the same capital cost and amortized annual cost, and amortized cost per gallon.

The capital amortization scheme labeled Societal Cost is used most often in our estimates of cost made below. It excludes the consideration of taxes, since taxes are considered to be transfer payments between various sectors of the economy and not true economic costs. The other two cost amortization schemes include corporate taxes, to represent the cost as the regulated industry might view it. The lower, 6%, rate of return represents the rate of return for the refining industry over the past 10-15 years. The higher, 10%, rate of return represents the rate of return which would be expected for an industry having the general aspects of the refining industry.

7.2.1.4.2 Fixed Operating Costs

Operating costs which are based on the cost of capital are called fixed operating costs. These costs are termed fixed, because they are normally incurred whether or not the unit is operating or shutdown. Fixed operating costs normally include maintenance needed to keep the unit operating, building costs for the control room and any support staff, supplies stored such as catalyst, property taxes and insurance.

We included fixed operating costs equal to 6.7% of the otherwise fully adjusted capital cost (i.e., including offsite costs and adjusting for location factor and including the capital cost contingency) and this factor was adjusted upwards using the operating cost contingency factor.[36] The breakdown of the base fixed operating cost percentage is as follows:

Maintenance costs: 3%
Buildings: 1.5%
Land: 0.2%
Supplies: 1%
Insurance: 1%.

Annual labor costs were taken from the refinery model developed by the Oak Ridge National Laboratory (ORNL).[37] This model has often been used by the Department of Energy to estimate transportation fuel quality and the impact of changes in fuel quality on refining costs. Labor costs are very small, on the order of one thousandth of a cent per gallon.

7.2.1.4.3 Utility and Fuel Costs

Variable operating costs only accrue as the unit is operating. Thus, they are usually based on unit throughput. When the unit is not operating, variable operating costs are zero. Thus, variable operating costs are based on calendar day throughput, not stream day capacity, to avoid over-counting these costs.

We obtained utility costs from EIA's 1999 Petroleum Marketing Annual report, which provides these costs by PADD.[38] We considered updating these costs. However, a review of more recent electricity showed little change from 1999. The price of liquid fuels changed significantly from 1999, but did not appear to represent long term trends. Thus, 1999 liquid fuel prices were also retained, with one change. We did add 5 c/gal to the price of high sulfur distillate fuel to represent the added cost of meeting the 15 ppm sulfur cap to.

Natural gas prices have been particularly volatile over the past three years, as natural gas use in electricity generation is increasing rapidly. Therefore, the price over any short period of time is unlikely to represent long term prices well. Thus, natural gas prices were averaged over 5 years starting at the end of 1996 and this average price was used here.

Steam demand is presented above in terms of pounds per hour. This was converted to BTUs per hour, assuming that the steam was provided at 300 psi (809 BTU per pound). We assume that the steam is generated using natural gas as fuel, at an efficiency of 50%, which was taken from Perry's Handbook.[39]

These utility and fuel costs are summarized in Table 7.2-25. For future analyses, we are considering using projections of future utility and fuel prices from EIA's most recent Annual Energy Outlook.

Table 7.2-25
Summary of Costs From EIA Information Tables for1999, and Other Cost Factors

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Electricity (cents per kilowatt-hour)	8.35	6.40	6.66	5.4	7.18
LPG (dollars per barrel)	17.09	14.11	14.49	14.53	17.05
Highway Diesel (cents per gallon)	53.1	55.9	51.5	62.4	64.0
Nonhighway Diesel (cents per gallon)	49.3	55.7	48.6	60.4	58.9
Gasoline (dollars per barrel)	27.0	25.9	24.9	28.9	30.0
Natural Gas ($/MMbtu)	4.15	4.24	2.98	3.15	3.91

7.2.1.4.4 Hydrogen Costs

Hydrogen costs are estimated for each PADD based on the capital and operating costs of installing or revamping a hydrogen plant fueled with natural gas. The primary basis for these costs is a technical paper published by Air Products, which is a large provider of hydrogen to refineries and petrochemical plants.[40] The particular design evaluated was a 50 million scf/day steam methane reforming hydrogen plant installed on the Gulf Coast. The capital cost includes a 20% factor for offsites. The process design parameters from this paper are summarized in the Table 7.2-26.

Table 7.2-26
Process Design Parameters for Hydrogen Production

Cost Component	Dollars per thousand standard cubic feet ($/MSCF)
Natural Gas	1.18
Utilities Electricity Water Steam	 0.03 0.03 -0.07
Capital/Fixed Operating Charges	0.83
Total Product Cost	2.00

Notes: Natural Gas @ $2.75/MMBTU; Steam @ $4.00/M lbs; Electricity @ $0.045 KWH

The estimates shown in Table 7.2-26 were adjusted to reflect natural gas and utility costs in each PADD (shown in Table 7.2-25). The steam costs were adjusted based on the cost of natural gas. The capital cost and fixed operating costs were increased by 8% to reflect inflation from 1998 to 2001.

We also adjusted the capacity of the hydrogen plant to reflect the capacity which would be typical for each PADD. The hydrogen plant capacity for PADD 3 represents the average of the existing hydrogen plants in the PADD and several third party units producing 100 million scf/day of hydrogen. For other PADDs, the average plant size was based on the average of refinery-based hydrogen plants within that PADD, obtained from the Oil and Gas Journal.[41] We incorporated PADD-specific offsite and construction location factors from Table 7.2-23, again assuming a 50-50 mix of new and revamped units. Table 7.2-27 summarizes the average plant size and the offsite and location factors for the installation of hydrogen plant capital for each PADD.

Table 7.2-27
Summary of Capital Cost Factors used for Estimating Hydrogen Costs by PADD

PADD	Capacity (million scf/day)	Offsite Factor	Construction Location Factor
1	15	1.19	1.5
2	34	1.19	1.3
3	65	1.15	1.0
4	19	1.38	1.4
5 Excluding CA and AK	15	1.23	1.2
Alaska	15	1.23	2.0

The adjusted hydrogen costs in each PADD are summarized in Table 7.2-28.

Table 7.2-28
Estimated Hydrogen Costs by PADD

PADD	Cost ($/1000 scf)
1	3.26
2	2.80
3	1.89
4	2.82
5 Excluding CA and AK	2.91
AK	3.69

7.2.1.4.5 Other Operating Cost Factors

Similar to the 15% contingency factor for capital costs, we included a 10% contingency factor to account for operating costs which are beyond the those directly related to operating the desulfurization unit.[42] This factor accounts for the operating cost of processing additional hydrogen sulfide in the amine plant, additional sulfur in the sulfur plant, and other costs which may be incurred but not explicitly accounted for in our cost analysis. We then increased this factor by 2% to account for reprocessing of off-specification material. Above, we estimated that 5% of all batches could require re-processing. However, since this material would have been desulfurized to a level close to the 15 ppm cap, the operating costs for reprocessing it should be much lower the second time around.

We also believe that refinery managers will have to place a greater emphasis on the proper operation of other units within their refineries, not just the new diesel fuel desulfurization unit, to consistently deliver diesel fuel under the proposed standards. For example, meeting a stringent sulfur requirement will require that the existing diesel hydrotreater and hydrocracker units operate as expected. Also, the purity and volume of hydrogen coming off the reformer and the hydrogen plant would be important for effective desulfurization. Finally, the main fractionator of the FCC unit would have to be carefully controlled to avoid significant increases in the distillation endpoint, as this could increase the amount of sterically hindered compounds sent to the diesel hydrotreater.

Improved control each of these units could involve enhancements to computer control systems, as well as improved maintenance practices.[43] Refiners may be able to recoup some or all of these costs through improved throughput. However, even if they cannot do so, these costs are expected to be less than 1% of those estimated below for diesel fuel desulfurization.[44] [45] No costs were included in the cost analysis for these potential issues.

7.2.1.5 How Refiners are Expected to Meet the Nonroad Sulfur Requirements

This section presents the methodology used to determine which refiners produce 15 and 500 ppm highway diesel fuel, 500 ppm NRLM diesel fuel, 15 ppm nonroad diesel fuel and heating oil during the four phases of the highway and NRLM diesel fuel programs. These four phases are:

1) June 1, 2006 - May 31, 2007: 15 ppm highway cap with temporary compliance option and small refiner provisions; no NRLM caps

2) June 1, 2007- May 31, 2010: 15 ppm highway cap with temporary compliance option and small refiner provisions; 500 ppm NRLM cap with small refiner provisions

3) June 1, 2010 - May 31, 2014: 15 ppm highway cap; 15 ppm nonroad cap with small refiner provisions; 500 ppm locomotive/marine cap

4) June 1, 2014 and beyond: 15 ppm highway cap; 15 ppm nonroad cap; 500 ppm locomotive/marine cap

As can be seen from these phases, there is significant overlap between the highway and NRLM diesel fuel sulfur programs. Thus, we begin our analysis below with a projection of which refiners would likely produce 15 ppm highway diesel fuel, first in 2006 and then in 2010. Then, we project which refiners would invest to produce 500 ppm NRLM diesel fuel and then 15 ppm nonroad diesel fuel.

In order to make these projections, we estimated how much highway and NRLM diesel fuel each refiner could produce. We obtained each U.S. refinery's actual production volumes of low-sulfur (highway) and high sulfur distillate during 2000 from the Energy Information Administration (EIA). Since the highway and NRLM diesel fuel programs phase in from 2006-2010, we projected these 2000 production volumes out to 2008, the mid-point of this time period. All the costs developed below presume economies of scale projected to exist in 2008.

Over the past 20 years, the production capacity of refineries which have remained in operation has steadily increased. EIA projects that this is likely to continue. Ideally, we would project each refinery's individual growth in production between 2000 and 2008. However, this information in not available. Therefore, we projected national average growth rates for highway and high sulfur distillate fuel, respectively. This appears to be quite reasonable. Not every refinery has increased capacity, nor has the increase been the same for every refinery showing an increase. However, a comparison of the crude oil distillation capacities of refineries in 1990 and 2002 indicate that a large majority of refineries have increased capacity. Thus, projecting the same growth rate for all refiners is reasonably consistent with past growth.

We projected growth in domestic refineries' production of diesel fuel based on growth in diesel fuel consumption. Based on the demand for low and high sulfur distillate fuel in 2000 and 2008 (discussed in Section 7.1 above), we determined that, absent this rule, the demand for highway diesel fuel and high sulfur distillate would increased by 24% and 8% between 2000 and 2008. Thus, the production volume of highway diesel fuel by each domestic refinery in 2000, from EIA, was increased by 24%, and that for high sulfur distillate was increased by 8%. This implicitly assumes that imports of both fuels will remain a constant percentage of total demand.

We made no changes in the production volumes of distillate fuel to account for any reduction in wintertime blending of kerosene that might occur with the implementation of 15 ppm highway or NRLM sulfur caps. Kerosene added to 15 ppm diesel fuel must itself meet a 15 ppm sulfur. Sometimes, kerosene is added at the refinery and the winterized diesel fuel is sold or shipped directly from the refinery. At other times, the kerosene blending is done at the terminal, downstream of the refinery. The former approach could mean adding kerosene to more diesel fuel than actual requires it. The latter approach would require that a distinct 15 ppm kerosene grade be produced and distributed. Much of this 15 ppm kerosene might be used in applications not requiring 15 ppm sulfur content. Adding pour point depressant is an alternative to blending kerosene. This can be done very flexibly at the terminals in areas facing very cold weather. Thus, we expect that the use of pour point depressants will increase and the terminal blending of kerosene will decrease. For kerosene blended into winter diesel fuel, the refinery could simply be added to the distillate being fed to the hydrotreater and desulfurized along with the rest of the 15 ppm diesel fuel pool.

The current amount of terminal blending of kerosene is difficult to estimate. Therefore, we have not attempted to estimate its current or future level and account for any change in this practice. In either case (terminal kerosene blending or the use of additives), the volume of distillate provided to terminals is roughly the same. Thus, we have simply based our projected costs of today’s proposal on current diesel fuel demand. This way, we are assured of including the cost of desulfurizing the total volume of diesel fuel consumed in NRLM diesel engines. The most important assumption here is that we have assumed that a separate, 15 ppm grade of kerosene will not be produced and distributed for downstream blending. This would entail additional production and distribution costs, which we believe will discourage this practice. Thus, we have not included these costs here.

The remainder of this section provides an overview of how we projected which refineries would likely produce highway and NRLM diesel fuel during the various phases of the program and how they would likely try to optimize the construction of their desulfurization equipment in order to comply with both programs.

7.2.1.5.1 Complying with the Highway Diesel Fuel Sulfur Program

The 15 ppm cap on highway diesel fuel takes effect June 1, 2006, when 80% of the highway diesel fuel produced by non-small refiners must meet this standard. Twenty percent of highway diesel fuel can remain at 500 ppm sulfur. Small refiners, which produce roughly 5 percent of highway diesel fuel are allowed to continue producing 500 ppm highway diesel fuel until January 1, 2010. Credits for over-production of 15 ppm diesel fuel can be traded within the PADD they are generated. These credits can be used through May 31, 2010. Thus, roughly 25% of highway diesel fuel can remain at 500 ppm sulfur through May 31, 2010.

The implementation date of the 15 ppm highway diesel fuel, June 1, 2006, occurs only 3 years from now. By the time that this proposal is finalized, only slightly more than two years will remain before June 1, 2006. This leadtime is not likely to be sufficient for refiners planning on producing 15 ppm highway diesel fuel in 2006 to fully coordinate these plans with this NRLM rule. Thus, as described below, we generally made the conservative assumption that refiners would make their plans for 2006 independent of the proposed NRLM diesel fuel program. However, as indicated above, many refineries could delay the production of 15 ppm highway diesel fuel until 2010 by purchasing credits. This would give them four additional years of leadtime and allow them to fully coordinate their plans for desulfurizing both highway and NRLM diesel fuel. Therefore, we have incorporated such coordination in our projections below.

As mentioned above, small refiners are allowed to continue producing 500 ppm highway diesel fuel until 2010 without the need to purchase credits. In addition, if a small refiner chooses to meet the 15 ppm cap with their highway diesel fuel, they are allowed to produce gasoline under their interim Tier 2 sulfur standards before the final 30 ppm Tier 2 standard applies. Other refineries located in the Geographic Phase-in Area (GPA) also have this option under the 2007 highway diesel fuel program.

Small and GPA refiners have already indicated to EPA whether they plan to take this option. This information was incorporated into our analysis by projecting that these refiners would begin producing 15 ppm highway diesel fuel in 2006, as opposed to 2010.

In order to produce 15 ppm highway diesel fuel, refiners have the choice of revamping their existing distillate hydrotreater or construct a new, grassroots hydrotreater. In the 2007 highway diesel fuel rule, we projected that 80% of the volume of 15 ppm fuel would be produced using revamped hydrotreaters and 20% would be produced using new, grassroots hydrotreaters. We have retained this projection in this analysis. As described in Chapter 5, refiners are still in the process of determining how they will produce 15 ppm highway diesel fuel and revamping their existing hydrotreater still appears likely to be feasible for most refiners.

A refiner's decision to revamp or construct a new unit will depend on many factors specific to that refinery. We lack the information necessary to project which decision individual refineries will make. Thus, we projected the cost of producing 15 ppm highway diesel fuel at each refinery using both a revamped hydrotreater and using a new, grass roots unit. An average cost was determined by weighting the revamp cost by 80% and the grass roots cost by 20%. As described in more detail in Section 7.2.2 below, we then used these average highway diesel fuel costs to determine which refineries were most likely to produce 15 ppm diesel fuel in 2006 and 2010.

The use of advanced desulfurization technologies was estimated in the same way. We made no attempt to determine which specific refineries would use each technology. We estimated the cost of producing 15 ppm diesel fuel using each technology at each refinery and then weighted these costs by the projected mix of desulfurization technologies applicable in that year.

For 2006, we assumed that refiners would only process their current highway diesel fuel volume (grown to 2008 production levels) to 15 ppm. In other words, no 15 ppm highway diesel fuel would be produced from current high sulfur distillate. However, for 2010, we evaluated the production of allowed 15 ppm highway diesel fuel from current high sulfur distillate. This could be at a refinery currently producing a mix of highway and high sulfur distillate, or just high sulfur distillate. This was done because some refineries currently produce very small quantities of highway diesel fuel, likely from naturally, low sulfur blendstocks. These refiners are unlikely to produce 15 ppm diesel fuel at such low volumes. Conversely, some refineries produce very large volumes of high sulfur distillate which could be controlled to 15 ppm with good economies of scale.

Once we had estimated each refinery's cost to produce 15 ppm highway diesel fuel, we assumed that those with the lowest cost in each PADD would be the most likely to produce this fuel in 2006. Thus, after considering the production of 15 ppm fuel by small and GPA refiners choosing to delay compliance with the Tier 2 gasoline sulfur standards, we fulfilled the remainder of each PADD's highway diesel fuel demand with 15 ppm highway diesel fuel from the other refineries, starting with those with the lowest cost per gallon and moving up until demand was met. Then in 2010, the remainder of highway diesel fuel demand was met by the next lowest cost production, either from current highway diesel fuel or high sulfur distillate fuel.

7.2.1.5.2 Complying with the 500 ppm NRLM Diesel Fuel Sulfur Standard in 2007

We used two basic criteria to project which refineries would likely produce 500 ppm NRLM diesel fuel in 2007. The first criterion was the refinery's ability to continue to sell high sulfur distillate. The Northeast has a large heating oil market. Thus, PADD 1 refineries were assumed to be able to continue to sell high sulfur distillate to this market if they desired. The same flexibility was assumed to apply to PADD 3 refineries which are either connected to one of the two large pipelines running from the Gulf Coast to the Northeast (Plantation and Colonial) or have access to ocean transport. Selected markets in PADD 5, such as Hawaii, also have significant heating oil demand, so some PADD 5 refineries were also assumed to have the flexibility to continue producing high sulfur distillate if they desired. Besides these refineries, however, all refineries in PADDs 2 and 4 and those in PADDs 3 and 5 not meeting the above criteria were assumed to have to produce 500 ppm NRLM diesel fuel starting June 1, 2007. While the proposed rule would not directly require this, we believe that for cost estimation purposes, this is a reasonable assumption.

Under the proposed NRLM diesel fuel program small refiners could continue selling high sulfur NRLM diesel fuel until June 1, 2010. Thus, these small refiners have more flexibility in selling high sulfur distillate fuel, as they can sell this fuel to either the heating oil or NRLM diesel fuel markets. We evaluated small refiners' ability to distribute high sulfur NRLM diesel fuel, as it is unlikely that common carrier pipelines would carry this fuel. Starting with the demand for NRLM diesel fuel in each PADD in 2008 from Section 7.1 above, we divided this demand by the square milage of each PADD to estimate an NRLM diesel fuel demand per square mile. We then determined the area over which each small refiner would have to distribute its high sulfur NRLM fuel in order to maintain its current production level. In all cases, assuming a circular shaped area, the radius of the circle was 100 miles or less. As this is easily within trucking distance, it was reasonable to assume that all small refiners could continue selling all of their high sulfur distillate fuel as either high sulfur distillate fuel or heating oil and delay producing any 500 ppm NRLM diesel fuel until 2010 at the earliest.

Table 7.2-29 compares the the number of refineries projected to have no choice but to produce 500 ppm NRLM diesel fuel to the number of refineries currently producing high sulfue distillate fuel.

Table 7.2-29
Number of Refineries Assumed to Have to Produce 500 ppm NRLM Diesel Fuel in 2007

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Having to Participate	1	23	11	8	10
Total Producing High Sulfur Distillate Fuel Today	13	23	41	8	20

For each PADD, we then added the production volumes of those refineries projected to have no choice but to produce 500 ppm NRLM diesel fuel to the volume of high sulfur NRLM diesel fuel which could be produced small refiners. We then compared these initial volumes of NRLM diesel fuel to the projected demand for NRLM diesel fuel in each PADD, as estimated in Section 7.1 above. We found that the demand for NRLM diesel fuel in PADDs 2 and 4 were already fulfilled by these refineries. This is not surprising given the assumptions described above. However, greater production of NRLM diesel fuel was required in PADDs 1, 3 and 5. This NRLM fuel would have to meet the proposed 500 ppm cap. We projected the refineries most likely to produce this fuel would be those facing the lowest per gallon desulfurization costs in each PADD.

All 500 ppm NRLM diesel fuel was assumed to be produced using conventional hydrotreating technology. The operating cost of this desulfurization is simply a function of the composition of each refinery's high sulfur distillate fuel, as well as some costs which vary by PADD, such as hydrogen, utilities, etc. However, a number of ways existed to estimate the capital cost, depending on how the potential production of 15 ppm diesel fuel in the future was considered and whether the refinery was already producing some of its distillate fuel as 500 ppm highway diesel fuel. The methodology used to estimate capital costs is summarized below.

As mentioned above, we generally presume that refiners projected to produce 15 ppm highway diesel fuel in 2006 cannot incorporate the production of 500 ppm or 15 ppm NRLM diesel fuel into their 2006 plans. Thus, with two exceptions, these refiners would have to construct a new, grass roots hydrotreater to produce 500 ppm NRLM in 2007.

One exception applied to refineries which produce only a very small amount of high sulfur distillate fuel compared to their volume of highway diesel fuel. This small volume is likely either off-specification diesel fuel or opportunistic sales to the non-highway diesel fuel market because of advantageous prices. Thus, in the cases where high sulfur distillate production represented 5% or less of total distillate fuel production, we assumed that the refinery could incorporate the high sulfur distillate into its highway hydrotreater design. The incremental capital cost assigned to the NRLM diesel fuel program was assumed to be the difference between the capital cost associated with a hydrotreater sized to process all the refinery's distillate fuel and that for a hydrotreater sized to treat just the highway diesel fuel volume. In this case, both hydrotreaters were assumed to be grass roots hydrotreaters. In other words, even if the high sulfur distillate fuel was being incorporated into a revamp of an existing highway diesel fuel hydrotreater, the incremental cost of increasing capacity was assumed to occur at a grass roots cost. As mentioned above, the operating cost was simply estimated based on the particular mix of blendstocks for that refinery and its location (i.e., PADD). As described above in subsection 7.2.1.2, this operating cost depends on how much of that refinery's high sulfur distillate is already being processed by a hydrotreater. Based on API/NPRA survey findings, refineries which currently have diesel fuel hydrotreaters were projected to blend a certain amount of hydrotreated material into their nonroad pool. This reduces the net hydrotreating cost, as the olefins and some polynuclear aromatics in the high sulfur distillate are already being saturated today.

The other exception is a refinery which is projected to construct a new, grass roots hydrotreater in 2006 to produce 15 ppm highway diesel fuel. This refinery would be able to produce 500 ppm NRLM fuel in 2007 with its existing highway unit. As mentioned above, we do not identify which individual refineries would likely construct a new grassroots unit in 2006. Thus, we simply assumed that 20% of the high sulfur distillate volume being produced from refineries projected to produce 15 ppm highway diesel fuel in 2006 could be desulfurized to 500 ppm with no capital costs.

The next set of refineries to be discussed are those which currently produce both highway and high sulfur distillate fuel and are not projected to produce 15 ppm highway diesel fuel until 2010. We presume that these refineries would have to build a new hydrotreater in 2007 in order to desulfurize their current high sulfur distillate to 500 ppm. However, due to the significant amount of leadtime available, we project that these refiners could design a revamp that would desulfurize all of their distillate fuel to 15 ppm in 2010 if they so desire.

Of course, refineries which only produce high sulfur distillate fuel today would have to install a new hydrotreater to produce 500 ppm NRLM fuel in 2007. We presume that this unit could be revamped in 2010 to produce 15 ppm nonroad diesel fuel in 2010, if so desired.

Table 7.2-30 presents the percentages of high sulfur distillate fuel production which falls in the categories described above.

Table 7.2-30
Production of High Sulfur Distillate: Interaction with Highway Diesel Fuel Program (%) [a]

	High Sulfur Refineries		Mixed Refineries Producing 15 ppm Highway Fuel in 2006		Mixed Refineries Producing 15 ppm Highway in 2010		Highway Refineries	
	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT
Number of Refineries	5	20	27	8	15	13	15	2
Percent of Nonroad Fuel	22	18	32	6	13	7	2	0

[a] "Highway" refinery: high sulfur distillate fuel production <u><</u>5% of total distillate fuel production
"High sulfur" refinery: high sulfur distillate fuel production <u>></u> 90% of total distillate fuel production
"Mixed refinery: refineries which are neither highway or high sulfur refineries
" W/Dist HT" means refineries currently having a distillate hydrotreater
"No Dist HT means refineries which do not currently have a distillate hydrotreater

Table 7.2-31 presents the estimation of the volume of NRLM diesel fuel which must be desulfurized to 500 ppm in 2007 in each PADD. PADDs 1 and 3 are shown combined since we assume that PADD 3 refineries can produce and ship 500 ppm NRLM fuel to PADD 1. The first line shows total volume of NRLM diesel fuel demand from Section 7.1. The next line shows the projected volume of highway fuel spillover to the NRLM fuel pool. This volume is subtracted from NRLM demand, as the spillover already meets the proposed 500 ppm cap. The difference is total demand for high sulfur NRLM diesel fuel, which is shown on the third line. The fourth line shows total small refiner volume, which does not need to be desulfurized in 2007. Then, current production volumes of high sulfur distillate from refineries which we project would not be able to continue marketing high sulfur distillate are shown. The difference, if any, is the final volume of 500 ppm NRLM diesel fuel which must be desulfurized. We presume that this final volume would be produced by refiners facing the lowest desulfurization costs in each PADD. In PADDs 2 and 4, this last volume is zero, because we project that all refineries in these PADDs would likely have to desulfurize their high sulfur distillate to 500 ppm in order to market it. The total volume of the last two rows of the table (highlighted in bold) yields the estimated total amount of high sulfur distillate which is expected to be hydrotreated to meet the 500 ppm NRLM diesel fuel in 2007. In PADD 2 and 4, this value is larger than the required volume. Thus, some volume of heating oil is being desulfurized in these PADDs to 500 ppm.

Table 7.2-31
NRLM Diesel Fuel Volume Needing Desulfurization: 2007-2010[a] (million gallons per year)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5
NRLM Diesel Fuel Demand	7143	5111	1173	937
Highway Spillover	1709	1728	779	215
Base High Sulfur NRLM Demand	5434	3382	394	722
Small Refiner Volume	490	369	10	202
Non-Small High Sulfur Demand	4944	3013	384	519
Non-Small Volume Required to Produce 500 ppm NRLM Fuel	**914**	**3385**	**488**	**84**
Remaining Demand for 500 ppm NRLM Diesel Fuel	**4030**	**0**	**0**	**435**

[a] Based on projected volumes for 2008

Table 7.2-32 presents an analogous set of volumes for 2010 assuming that no 15 ppm nonroad diesel fuel cap was implemented. (This situation is analyzed to allow the long-term analysis of the 500 ppm NRLM diesel fuel cap independent of the 15 ppm nonroad diesel fuel cap). The primary difference is the absence of the small refiner volume.

Table 7.2-32
NRLM Diesel Fuel Volume Needing Desulfurization in the Absence of a 15 ppm Nonroad Diesel Fuel Cap: 2010 and beyond[a] (million gallons per year)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5
NRLM Diesel Fuel Demand	7,143	5,111	1,173	937
Highway Spillover	1,709	1,728	779	215
Base High Sulfur NRLM Demand	5,434	3,382	394	722
Small Refiner Volume	0	0	0	0
Net High Sulfur Volume	5,434	3,382	394	722
Non-Small Volume Required to Produce 500 ppm NRLM Fuel	**1,344**	**3,755**	**498**	**286**
Remaining Demand for 500 ppm NRLM Diesel Fuel	**4,090**	**0**	**0**	**435**

[a] Based on projected volumes for 2008

In Table 7.2-33, the refineries which are projected to produce 500 ppm NRLM diesel fuel after the program is fully phased in are characterized by whether they produce predominantly high sulfur distillate, a mix of highway and high sulfur distillate or predominantly highway diesel fuel. Like Table 7.2-32, Table 7.2-33 is provided to enable the long-term evaluation of the 500 ppm NRLM standard in the absence of the 15 ppm nonroad diesel fuel cap.

Table 7.2-33
Characterization of the Refineries Projected to Produce 500 ppm NRLM Fuel for 2007

	Nonroad Only Refineries		Mixed Refineries Complying with Highway in 2006		Mixed Refineries Complying with Highway in 2010		Highway Only Refineries	
	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht
Number of Refineries	0	14	15	4	10	9	10	0

7.2.1.5.3 Complying with the 15 ppm Nonroad Sulfur Standard for 2010

We followed the same basic methodology for projecting the cost of 15 ppm nonroad diesel fuel in 2010, as was described in the previous section for the production of 500 ppm NRLM diesel fuel in 2007. We first considered whether refineries projected to produce 500 ppm NRLM diesel fuel in 2007 could continue to do so in 2010 if they so desired. A few refineries were found to have a sufficiently large volume of 500 ppm NRLM diesel fuel in 2007 and were located distant from a pipeline or a navigable waterway that it was deemed unlikely that they could sell all of this fuel to the locomotive and marine diesel fuel markets. These refineries were assumed to have to process this fuel further to 15 ppm.

All other refineries which produced 500 ppm NRLM diesel fuel in 2007 were assumed to have the option of producing 15 ppm nonroad diesel fuel in 2010 or continuing their production of 500 ppm fuel for the locomotive and marine diesel fuel markets. Refineries which did not produce 500 ppm NRLM diesel fuel in 2007 (or 2010 after the expiration of small refiner provisions) were not considered likely to produce 15 ppm nonroad fuel in 2010 (or 2014 after the expiration of small refiner provisions). Since the locomotive and marine diesel fuel markets exist essentially everywhere in the country, far fewer refineries were projected to have to produce 15 ppm nonroad fuel in 2010 compared to 500 ppm NRLM fuel in 2007.

Again, we evaluated small refiners' ability to market 500 ppm NRLM fuel in 2010 and found that they could do so by truck. Thus, we assumed that they would either do so or would produce 15 ppm fuel and sell credits to other refiners. In either case, their current high sulfur distillate production volume would only have to meet a 500 ppm cap in 2010. Table 7.2-34 shows the number of refineries projected to have little flexibility to avoid producing 15 ppm nonroad diesel fuel in 2010.

Table 7.2-34
Number of Refineries Assumed to Have to Produce 15 ppm Nonroad Diesel Fuel in 2010

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Having to Participate	1	8	0	4	5
Total Producing High Sulfur Distillate Today	13	23	41	8	17

As already described in the previous section, the capital cost for producing 15 ppm nonroad diesel fuel depends on whether the refinery currently produces highway diesel fuel and when it is projected to first produce 15 ppm diesel fuel. Refineries producing less than 5% of their distillate as high sulfur were assumed to process all their distillate in one desulfurization unit, regardless of whether this was a new unit or a revamp, whether it was first produced in 2006 or 2010.

As mentioned above, 20% of the refineries producing 15 ppm highway diesel fuel were presumed to install a new, grass roots unit to do so. These new units would desulfurize high sulfur distillate now being desulfurized to 500 ppm down to 15 ppm. These refineries could therefore produce 500 ppm NRLM diesel fuel using their existing highway diesel fuel hydrotreater. In order to produce 15 ppm nonroad diesel fuel in 2010, we assumed that these refineries would need to construct a grass roots desulfurization unit. Since the highway hydrotreater could not be revamped in 2006 in order to produce 15 ppm highway diesel fuel, it could also not be revamped to produce 15 ppm nonroad diesel fuel. We also assume that any new hydrotreater constructed in 2007 could be revamped to produce 15 ppm nonroad diesel fuel in 2010, due to its recent construction and the presumption that refiners would consider the 15 ppm cap when designing their 2007 unit.

Otherwise, the projection of the types of units that could be installed to produce 15 ppm nonroad units was consistent with the description presented in the previous section. Refineries only producing high sulfur distillate today could revamp the hydrotreater added in 2007 to produce 15 ppm nonroad diesel fuel. Refineries producing less than 5% of their distillate fuel as high sulfur fuel and projected to produce 15 ppm highway fuel in 2010 were assumed to be able to revamp their highway unit, allowing them to process the small amount of high sulfur distillate fuel in the same unit. Refineries producing both highway and high sulfur distillate today and projected to produce 15 ppm highway diesel fuel in 2010 were assumed to be able to process all their distillate to 15 ppm in a single unit (80% revamped, 20% grass roots).

The methodology for estimating the capital costs for the mixed refineries is somewhat complex. Table 7.2-34b shows a description of the different new and revamp unit options to enable refiners to meet the 15 ppm highway and nonroad standards.

Table 7.2-34b
Summary of New and Revamp Options by Refinery Situation

New vs Revamp	Refinery Configuration	Fuel Category	Type of Added Unit
Revamped Highway Hydrotreater in 2010	Refinery with Distillate Hydrotreater	Highway	Revamp of Existing Highway Hydrotreater
		Non-Highway treated in Hwy Hydrotreater	Revamped Treater
		Non-Highway	Revamp of Hydrotreater installed in 2007
	Refinery w/o Distillate Hydrotreater	Highway	Revamp of Existing Highway Hydrotreater
		Non-Highway	Revamp of Hydrotreater installed in 2007
New Highway Hydrotreater added in 2010	Refinery with Distillate Hydrotreater	Highway	New Hydrotreater
		Non-Highway treated in Hwy Hydrotreater	New Hydrotreater
		Non-Highway	Revamp of Hydrotreater installed in 2007
	Refinery w/o Distillate Hydrotreater	Highway	New Treater
		Non-Highway	Revamp of Hydrotreater installed in 2007

An example is provided here to better explain the capital cost calculation methodology. This example is made for a refinery on the Gulf Coast with a distillate hydrotreater and this refinery will comply with the highway diesel sulfur program in 2010 and also comply with the nonroad diesel fuel sulfur program in 2010. This refinery also has an FCC unit and a hydrocracker which is large enough to process all the LCO from the FCC unit. Thus, the highway and nonhighway pools would be composed of straight run diesel fuel only. The refinery produces 40,000 bbl/day of highway diesel fuel and 20,000 bbl/day of nonhighway distillate, and the hydrocracker produces 15,000 bbl/day of hydrocracked distillate, 10,000 bbl of which goes into the highway pool and 5,000 bbl of which goes into the nonhighway pool. This refinery is presumed to use the Linde hydrotreating technology to comply with the 2010 standards. As shown in Table 7.2-21, refineries with distillate hydrotreaters on the Gulf Coast are presumed to hydrotreat 44 percent of their nonhighway distillate. Thus, 44 percent of the 15,000 bbl per day nonhighway pool (20,000 bbl/day total nonhighway volume minus the 5000 bbl/day which is hydrocracked), or 6600 bbl/day is already hydrotreated, while 8400 bbl/day is not hydrotreated. Thus to calculate the capital cost for the highway and nonroad programs the following apply:

The capital cost of the highway hydrotreater is estimated using an exponential equation termed the "six-tenths rule" (from Subsection 7.2.1.4.1 above). The equation is as follows:

$(Sb/Sa)^{e}xCa=Cb$,
Sa is the size of unit quoted by the vendor,
Sb is the size of the unit for which the cost is desired,
e is the exponent, which is 0.65 for desulfurization units
Ca is the cost of the unit quoted by the vendor (which is 25000 bbl/day), and
Cb is the desired cost for the different sized unit.

The cost of the highway hydrotreater would therefore be calculated to be

$(30{,}000/25{,}000)^{0.65}$ x \$21 million = \$23.6 million
This value needs to be increased by a factor of 1.2 to account for the offsites, and for the location, which is 1.0 for the Gulf Coast (from Subsection 7.2.1.4.1 above).

This increases the highway diesel fuel hydrotreater cost to \$28.4 million.

If the highway hydrotreater were to be revamped, it would cost \$13.1 million using the same methodology but substituting a \$10.6 million figure for the base unit with a 25,000 bbl/day capacity for the \$21 million figure and using a 1.1 factor for offsites instead of 1.2. Although calculating the revamped cost seems irrelevant for this example, this value is actually used as described below.

The cost for complying with the Nonroad Program is calculating by calculating the combined Nonroad/Highway capital cost and subtracting the highway program capital cost from it. Thus, using the same equation, the cost for the combined new Nonroad/Highway hydrotreater is calcualated as follows:

$(45{,}000/25{,}000)^{0.65}$ x \$21 million = Cb which is \$30.8 million which increases to \$36.9 using the offsite factor (1.2).

To calculate the capital cost of a new Nonroad unit, the new Highway unit capital cost is subtracted from the combined, new Highway/Nonroad capital cost (\$36.9 - \$23.6 to yield the Nonroad new unit capital cost which is \$13.3. (The economy of scale benefit is apparent by calculating the capital cost of a dedicated new, nonroad only unit which is \$18.1 million and comparing it to the \$13.3 million figure.)

However, a portion of nonhighway distillate which is being desulfurized down to 500 ppm in 2007 only needs to be revamped. A credit is claimed for this fraction by calculating the economy of scale capital cost for a revamped unit and ratio the two costs.

A combined Highway/Nonroad revamped unit is calculated as follows

$(45{,}000/25{,}000)^{0.65}$ x \$10.6 million x 1.1 = \$17.1 million, then the Nonroad portion is calculated by subtracting the revamped highway hydrotreater capital cost (\$17.1 million - \$13.1 million) which is \$4.0 million.

The Nonroad capital cost is calculating by apportioning the capital cost estimates for to the respective portions of the Nonroad pool. As stated above, 44 percent of the Nonroad pool is hydrotreated and this portion requires a new unit cost while the 56 percent balance only requires the cost of a revamp. Thus, 44 percent of the capital cost is \$13.3 million and 56 percent of the capital cost is \$4.0 million, yielding a volume weighted cost of \$8.1 million.

Table 7.2-35 presents the estimated volume of nonroad diesel fuel which must be desulfurized in 2010 to 15 ppm by PADD. The methodology used to develop these figures is the same as that described above for the required volume of 500 NRLM diesel fuel (Table 7.2-31).

Table 7.2-35
Nonroad Diesel Fuel Needing Desulfurization: 2010-2014[a]
(million gallons per year)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5
Nonroad, Diesel Fuel Demand	4440	3559	822	665
Highway Spillover	1018	1168	524	157
Base 500 ppm Nonroad Volume	3422	2391	298	508
Small Refiner Volume	407	369	10	202
Net Volume of 15 ppm Nonroad Fuel	3015	2022	288	306
Non-Small Volume Having to Produce 15 ppm Nonroad Diesel Fuel	**0**	**1032**	**370**	**84**
Remaining Demand for 15 ppm Nonroad Diesel Fuel	**3015**	**989**	**0**	**222**

[a] Based on projected volumes for 2008

Table 7.2-36 presents an analogous set of volumes for 2014. The difference is the absence of the small refiner volume.

Table 7.2-36
Nonroad Diesel Fuel Volume Needing Desulfurization: 2014 and Thereafter[a]
(million gallons per year)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5
Required Supply of Nonroad, Diesel Fuel	4,440	3,559	822	665
Highway Spillover	1,018	1,168	524	157
Net 500 ppm volume to be treated	3,422	2,391	298	508
Small Refiner Volume	0	0	0	0
Net Volume of 15 ppm Nonroad Fuel	3,422	2,391	298	508
Non-Small Volume Required to Produce 15 ppm Nonroad Diesel Fuel	**23**	**1,157**	**370**	**108**
Remaining Demand for 15 ppm Nonroad Diesel Fuel	**3,399**	**1,234**	**0**	**401**

[a] Based on projected volumes for 2008

In Table 7.2-37, the refineries which are projected to produce 15 ppm nonroad diesel fuel after the program is fully phased in are characterized by whether they produce predominantly high sulfur distillate, a mix of highway and high sulfur distillate or predominantly highway diesel fuel.

Table 7.2-37
Characterization of the Refineries Projected to Produce 15 ppm Nonroad Diesel Fuel [a]

	Nonroad Only Refineries		Mixed Refineries Complying with Highway in 2006		Mixed Refineries Complying with Highway in 2010		Highway Only Refineries	
	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht	W/Dist HT	No Dist Ht
Number of Refineries	0	4	9	4	7	5	0	8

[ar] Refineries listed in No dist Ht column do not currently have a highway diesel hydrotreater, ie make highway fuel from straight run, hydrocrackate and other low sulfur blendstocks. These refineries would install a new hydrotreater to make 500 ppm diesel for the two step program which is revamped to make 15 ppm nonroad.

7.2.1.5.4 Projected Use of Advanced Desulfurization Technologies

In Chapter 5, we projected of the mix of technologies used to comply with a program being implemented in any year. This projection took into account the factors which affect the decisions by refiners in choosing a new technology. The projected mix of technologies for certain important years is summarized here for the reader's benefit.

Table 7.2-38
Projected Use of Advanced Desulfurization Technologies for Future Years

	2008	2009	2010	2012+
Conventional Technology	60	40	20	0
Linde Isotherming	20	30	40	50
Phillips SZorb	20	30	40	50

7.2.2 Refining Costs

In this section, we present the refining costs for the proposed NRLM diesel fuel program, as well as for several alternative fuel programs evaluated in the process of developing this proposal. The first step in developing the refining costs for the proposal was to estimate the cost of producing 500 and 15 ppm diesel fuel for each of the 143 refineries currently producing either highway diesel fuel or high sulfur diesel fuel, or both fuels. These costs were estimated for both conventional and advanced desulfurization technologies using the methodology developed in Section 7.2 above. The capital and operating cost factors for each desulfurization technology, are the same for each refinery. However, each refinery's projected 2008 production of highway diesel fuel and high sulfur distillate, its LCO fraction and other cracked stocks fraction and its location (i.e., PADD) were also used, which led to different projected costs to produce 500 and 15 ppm diesel fuel for each refinery. As the mix of desulfurization technologies is projected to vary with the implementation year for the 15 ppm standard, the cost of producing 15 ppm fuel varies with year of implementation for each refinery in the U.S.

The remainder of this section presents the refining costs for the various fuel programs. Refining costs to meet the 2007 highway diesel fuel program are presented first, as this provides the basis for evaluating the additional costs for NRLM diesel fuel sulfur control. Refining costs for the proposed two-step NRLM fuel program are presented next, followed by the refining costs for the alternative NRLM fuel programs evaluated in the developing the proposal. Finally, we present the stream of capital costs which would be required by the NRLM fuel program, in the context of other environmental requirements facing refiners in the same timeframe, namely the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program. All per gallon costs presented in this section would apply to the volume of NRLM disel fuel actually being desulfurized under the proposed fuel program. These costs would not apply to NRLM diesel fuel already meeting highway diesel fuel sulfur standards (i.e., spillover fuel).

7.2.2.1. 15 ppm Highway Diesel Fuel Program

Highway diesel desulfurization cost to15 ppm were estimated in 2006 and 2010 to provide a basis from which to estimate the costs of the NRLM program. The methodology used here is nearly identical to that used to develop the costs presented in the 2007 highway diesel fuel rulemaking. The two differences are: 1) we used more recent estimates of each refinery's current production of highway diesel fuel and high sulfur distillate, and 2) we modified the methodology used to estimate the cost of expanding the production volume of highway fuel by desulfurizing current high sulfur distillate. Both of these changes were described in Section 7.2.1 above.

We projected the specific refineries which will produce 15 ppm highway diesel fuel in 2006 based on their projected cost per gallon. We did not consider the potential for refineries to desulfurize their current high sulfur distillate fuel. The lowest cost refiners were assumed to produce 15 ppm highway diesel fuel until at least 80% of the required supply of highway diesel fuel was fulfilled. The exception to this was that several refineries with potentially higher desulfurization costs were also assumed to produce 15 ppm fuel in 2006. These refineries are eligible to select a delay in their applicable Tier 2 gasoline sulfur standards if they produce 15 ppm highway diesel fuel in 2006. Several refiners have informed EPA that they are planning to select this compliance option. Therefore, we projected that these refineries would produce 15 ppm highway diesel fuel in 2006.

We projected specific refineries to produce additional 15 ppm highway diesel fuel in 2010 again based on their projected cost per gallon. The lowest cost refiners were assumed to produce 15 ppm highway diesel fuel until at least 100% of the required supply of highway diesel fuel was fulfilled. Initially, only distillate volume which is currently highway diesel fuel was considered. After doing so, we determined that 13 refineries faced very high costs of producing 15 ppm highway diesel fuel, due solely to their extremely low production volumes and resulting poor economies of scale for a new or revamped hydrotreater. It is very likely that these refineries produce highway diesel fuel today from blendstocks which are naturally low in sulfur. It is very unlikely that they currently have a hydrotreater of such low capacity. Therefore, we do not believe that it is likely that these refineries would construct a new hydrotreater to produce such a low volume of highway fuel. Thus, we assumed that they would not produce 15 ppm highway diesel fuel in 2010. We replaced their production volume with 15 ppm diesel fuel produced from high sulfur distillate currently being produced by five refiners currently producing both highway diesel fuel and high sulfur distillate fuel.

The projected costs for producing 15 ppm highway diesel fuel are summarized in Table 7.2-39.

Table 7.2-39
Highway Diesel Desulfurization Costs to Meet a 15 ppm Cap Standard
($2002, 7% ROI before taxes)

	Refineries Producing 15 ppm in 2006	Refineries First Producing 15 ppm in 2010	All Refineries
Number of Refineries	74	40	114
Total Capital Cost ($Million)	4,210	1,240	5,450
Average Capital Cost per Refinery ($Million)	56.9	31.1	47.8
Average Operating Cost per Refinery ($Million/yr)	13.6	4.7	9.0
Total Cost (c/gal)	3.5	3.8	3.6

As can be seen, we project that 74 refineries will invest to produce 15 ppm highway fuel in 2006, with a total capital cost of $4.21 billion ($57 million per refinery). All of the fuel desulfurized to 15 ppm is produced from current highway diesel fuel. The average cost to produce 15 ppm highway diesel fuel is 3.5 cents per gallon. These costs assumed that all this 15 ppm fuel is being produced using conventional hydrotreating.

We project that 40 additional refineries will invest to produce 15 ppm highway diesel fuel in 2010, as the temporary compliance option expires. The required capital cost will be $1.24 billion ($31 million per refinery). The average cost for 15 ppm fuel newly produced in 2010 is 3.8 cents per gallon, which is 0.3 cents higher than 15 ppm fuel first produced in 2006. Five refineries invest to desulfurize both their current highway and high sulfur distillate fuels to make 15 ppm fuel, while 13 refineries cease production of highway diesel fuel.

Overall, 114 refineries produce the 15 ppm diesel fuel under the 2007 highway diesel fuel program, with a total capital cost of $5.45 billion ($47.8 million per refinery). The average refining cost in 2010 will be 3.6 cents per gallon of fuel.

7.2.2.2 Costs for Proposed Two Step Nonroad Program

The proposed two step program specifies that nonroad, locomotive and marine volumes have sulfur caps of 500 ppm in year 2007 with nonroad sulfur further reduced to 15 ppm in year 2010. Small refineries have three and four year delay provisions for complying with the 500 ppm and 15 ppm, respectively. Small refiner's can sell high sulfur diesel fuel in the NRLM market in years 2007-2010, while small refiners can sell 500 ppm fuel in the nonroad market in years 2010-2014. In lieu of physically selling these higher sulfur fuels to the NRLM and nonroad markets, small refiners can sell their credits to other refiners, who can then do the same. From the point of view of this cost analysis, because these small refiner credits can be sold to others, the small provisions have the net result of reducing the volume of NRLM diesel fuel which would have to meet the 500 ppm cap in 2007 and the volume of nonroad diesel fuel which would have to meet the 15 ppm cap in 2010. Small refiners need not be the refiners producing the high sulfur NRLM diesel fuel in 2007-2010, nor the 500 ppm nonroad diesel fuel in 2010-2014.

Below, we first present an overall summary of the costs of the entire proposed NRLM fuel program. Then we present in greater detail the refining costs for the three steps of the proposed NRLM fuel program: 1) the 500 ppm NRLM diesel fuel cap in 2007, 2) the 15 ppm nonroad diesel fuel cap and 500 ppm locomotive and marine diesel fuel cap in 2010, and 3) the 15 ppm nonroad diesel fuel cap and 500 ppm locomotive and marine diesel fuel cap in 2014 after the expiration of small refiner provisions.

Overall, by 2014, we project that 62 refineries would invest to make either 15 or 500 ppm NRLM diesel fuel. We project that 37 of these refineries would produce 15 ppm nonroad diesel fuel, with the remaining 25 producing 500 ppm locomotive and marine diesel fuel. The projected costs to meet these standards are summarized in the two tables below. Table 7.2-40 presents the total refining costs per gallon for the various steps in and fuels of the proposed program. Table 7.2-41 presents the costs for average and small refineries.

Table 7.2-40
Number of Refineries and Refining Costs for the Proposed Two Step Program

	Year of Program	500 ppm Fuel		15 ppm Fuel	
		All Refineries[a]	Small Refineries	All Refineries[a]	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	42	0	0	0
	2010-2014	37	19	25	0
	2014+	25	12	37	7
Refining Costs (c/gal)	2007-2010	2.1	0	0	0
	2010-2014	2.3	3.3	4.2	0
	2014+	2.2	3.3	4.4	8.2

[a] Includes small refiners.

Table 7.2-41
Refining Costs for Fully Implemented (2014 and Beyond)
Proposed Two Step Program ($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	62	19
Total Refinery Capital Cost ($Million)	1240	215
2007	449.0	0
2010	627.0	131.0
2014	163.0	86.0
Average Refinery Capital Cost ($Million)	20.0	11.3
Average Refinery Operating Cost ($Million/yr)	4.1	1.3

As can be seen, total capital costs would be $1,240 million for the entire proposed NRLM fuel program (average of $20.0 million per refinery). The per gallon cost of both 500 ppm and 15 ppm diesel fuels would be 2.2-2.3 and 4.2-4.4 cents, respectively. Small refiners projected to produce either 500 or 15 ppm NRLM diesel fuel would face higher costs on a per gallon basis. At the 500 ppm level, small refiner costs would be about 50% greater, at 3.3 cents per gallon. At the 15 ppm level, small refiner costs would be over 80% greater, at 8.2 cents per gallon. Total capital costs for the 19 small refineries would be $215 million (average of $11.3 million per refinery).

7.2.2.2.1 Refining Costs in Year 2007

We projected the specific refineries which would produce 500 ppm NRLM fuel beginning in 2007 in two steps. First, we identified specific refineries which would have difficulty marketing high sulfur distillate fuel in 2007 because of the small volume of heating oil sales in their PADD. These refineries were projected to hydrotreat all their high sulfur distillate fuel to 500 ppm regardless of the cost per gallon. However, we excluded small refiners in this step, as they could sell their high sulfur diesel fuel to either the NRLM diesel fuel market or the heating oil market. Second, if these refineries did not produce the required volume of 500 ppm NRLM fuel in a specific PADD, the refineries with the lowest cost of producing additional volume of 500 ppm fuel were projected to do so until sufficient 500 ppm NRLM fuel was produced in each PADD.

We project that 42 refiners would produce 500 ppm NRLM fuel in 2007. Of these 42 refineries, we project that 32 would install new hydrotreaters, seven "highway" refiners would perform a relatively minor revamp to their highway distillate hydrotreaters and three refineries could produce 500 ppm NRLM diesel fuel with an idled highway hydrotreater.[I] These last three

[I] "Highway" refineries' high sulfur diesel fuel production is no more than 5 percent of their total no. 2 distillate production. High sulfur refineries high sulfur diesel fuel production is no refineries were projected to build a new hydrotreater to comply with the 15 ppm highway diesel fuel standard. Therefore, their current highway hydrotreater would be available to produce 500 ppm NRLM fuel.

Small refiners were assumed to exercise small refiner delay provisions and not produce 500 ppm fuel in 2007 unless their desulfurization costs were competitive with other refiners who invested to make 500 ppm diesel fuel. However, none of the small refiners costs for producing a 15 ppm fuel were competitive with the other refineries which produced sufficient volumes of 500 ppm NRLM fuel to satisfy market demand. Thus, small refiners have no cost associated with implementing the 500 ppm standard in 2007. Small refiners would sell their high sulfur diesel fuel to the NRLM market with no attendant refining cost.

The cost of the 500 ppm NRLM cap in 2007 is summarized in Table 7.2-42 below.

Table 7.2-42
Refining Costs for 500 ppm
NRLM Diesel Fuel in 2007 ($2002, 7% ROI before taxes)[a]

	All Refineries
Number of Refineries	42
Total Refinery Capital Cost ($Million)	449
Average Refinery Capital Cost ($Million)	10.7
Average Refinery Operating Cost ($Million/yr)	3.3
Amortized Capital Cost (c/gal)	0.6
Operating Cost (c/gal)	1.5
Cost Per Affected Gallon (c/gal)	2.1

[a] With consideration of small refiner provisions.

We project that the 42 refiners would incur a total capital cost of $499 million (average of $11 million per refinery). The total refining cost for the 500 ppm NRLM diesel fuel sulfur cap is 2.1 cents per gallon of affected fuel volume, including both operating and amortized capital costs.

We repeated this 2007 analysis without the small refiner provisions (i.e., for a higher volume of 500 ppm NRLM diesel fuel. (This situation is equivalent to the proposed 500 ppm NRLM standard in 2010 without the addition of the 15 ppm nonroad diesel fuel standard). The

less than 95 percent of their total no. 2 distillate production. All other refiners are termed mix refineries. Mix refineries projected to produce 15 ppm highway diesel fuel in 2006 and 2010 are termed 2006 mix refiners and 2010 mix refiners, respectively.

availability of this long term cost is useful in the legal justification of the 500 ppm standard.

With the expiration of the small refiner provisions regarding the 500 ppm NRLM marine diesel fuel sulfur standard, an additional 20 refiners would invest to produce 500 ppm NRLM diesel fuel, for a total of 62 refineries producing 500 ppm NRLM diesel fuel. The overall refining cost would increase very slightly to 2.2 cents per gallon. Of the 20 new refineries, 19 would be small refineries. The reason for the predominance of small refiners in this step is that most of these 19 small refiners would have difficulty marketing high sulfur distillate fuel in 2010 because of the small volume of heating oil sales in their PADD. On average, the refining cost for small refiners would be more than 60% higher than that of the non-small refiner, 3.3 cents per gallon. Various costs of the 500 ppm NRLM diesel fuel cap without the small refiner provisions are summarized in Table 7.2-43.

Table 7.2-43
Refining Costs for 500 ppm NRLM Diesel Fuel
in 2007 without Small Refiner Provisions ($2002, 7% ROI before taxes)[a]

	All Refineries	Nonsmall Refineries	Small Refineries
Number of Refineries	62	43	19
Total Refinery Capital Cost ($Million)	600	468	131
Average Refinery Capital Cost ($Million)	9.7	10.9	6.9
Average Refinery Operating Cost ($Million/yr)	2.8	3.6	0.9
Capital Cost (c/gal)	0.6	0.5	1.5
Operating Cost (c/gal)	1.6	1.5	1.8
Cost Per Affected Gallon (c/gal)	2.2	2.0	3.3

[a] Equivalent to the costs of the 500 ppm NRLM cap in 2010 without the 15 ppm nonroad cap.

7.2.2.2.2 Refining Costs in Year 2010

In 2010 under the proposal, all nonroad diesel fuel except that represented by small refiners must meet a 15 ppm cap. The specific refineries producing this 15 ppm nonroad diesel fuel were identified in a two step process, analogous to the procedure followed for 2007. First, of those refineries producing 500 ppm NRLM fuel in 2007, we identified specific refineries which would have difficulty marketing 500 ppm locomotive and marine diesel fuel in 2010 because of difficulty economically transporting this fuel in large quantities. Second, the refineries with the lowest cost of producing 15 ppm fuel were projected to do so until sufficient 15 ppm nonroad fuel was produced in each PADD.

After the refineries projected to produce 15 ppm nonroad diesel fuel in 2010 were identified, this left a few refineries still producing 500 ppm diesel fuel from those first producing 500 ppm

NRLM diesel fuel in 2007. Additional refineries were then identified in each PADD until the total production volume of 500 ppm diesel fuel reached the required volume of locomotive and marine and small refiner nonroad diesel fuel.

We project that 25 refineries would produce 15 ppm nonroad diesel fuel in 2010. Two of these refineries would install new hydrotreaters, as they were using their existing highway diesel hydrotreater to produce 500 ppm NRLM diesel fuel in 2007. Five "highway" refineries would incorporate their current high sulfur distillate fuel with their highway diesel fuel when they revamp their highway hydrotreater to produce 15 ppm highway diesel fuel in 2010. The remaining 18 refineries are projected to revamp their new nonroad hydrotreater built in 2007 to produce 500 ppm NRLM diesel fuel.

The refining costs to produce 15 ppm nonroad fuel in 2010 are presented in Table 7.2-44. The first column of costs shows the total refining cost relative to today's uncontrolled sulfur levels. The last column shows the incremental costs relative to the cost of producing 500 ppm fuel in 2007. Small refiners were assumed to exercise small refiner delay provisions and not produce 15 ppm fuel in 2010 unless their desulfurization costs were competitive with other refiners in whom invested to make 15 ppm diesel fuel. However, none of the small refiners costs for producing a 15 ppm fuel were competitive with the other refineries which produced sufficient volumes of 15 ppm nonroad fuel to satisfy market demand. Thus, small refiners are projected to have no cost associated with the 15 ppm nonroad diesel fuel standard in 2010.

Table 7.2-44
Refining Costs to Produce 15 ppm Nonroad Diesel Fuel in 2010
($2002, 7% ROI before taxes)

	All Refineries	Incremental Desulfurization Cost 500ppm to15 ppm All Refineries
Number of Refineries	25	25
Total Refinery Capital Cost ($Million)	720	477
Average Refinery Capital Cost ($Million)	28.8	19.1
Average Refinery Operating Cost ($Million/yr)	6.0	2.6
Capital Cost (c/gal)	1.5	0.9
Operating Cost (c/gal)	2.7	1.2
Cost Per Affected Gallon (c/gal)	4.2	2.1

The desulfurization equipment used to meet the 500 ppm standard would have been built three years prior, and we expect it would have been designed to facilitate further processing to 15 ppm sulfur through a revamp. However, a few refiners which were expected to use their existing highway diesel hydro treaters to meet the proposed 500 ppm cap in 2007 would likely have to construct new equipment in 2010 to meet the 15 ppm cap on nonroad diesel fuel.

We project that 25 refineries would invest to produce 15 ppm nonroad in 2010 at an incremental capital cost of $477 million. Including the cost of meeting the 500 ppm NRLM cap in 2007, these 25 refineries' total capital costs would be $720 million. The incremental cost of producing 15 ppm nonroad diesel fuel is 2.1 cents per gallon, for a total cost of 4.2 cents per gallon. The incremental cost of 2.1 cents per gallon to desulfurize 500 ppm diesel fuel to a 15 ppm cap is 1.5 cents per gallon less than the 3.6 cent per gallon cost estimated above for the 15 ppm highway diesel fuel cap. There are three reasons for this. One, most 15 ppm highway fuel is being initially produced in 2006, when we project little or no use of advanced desulfurization technologies. Two, current highway hydrotreaters are at least 10 years old. We project that only 80% of them can be revamped to produce 15 ppm diesel fuel. Thus, the cost for 15 ppm highway diesel fuel includes new hydrotreaters for 20% of the volume. However, over 90% of 500 ppm nonroad diesel fuel would be produced in 2007 using new hydrotreaters. All of these new units could be designed to be revamped in 2010. Three, we focused the production of 15 ppm highway diesel fuel to a large degree on those refiners already producing 500 ppm highway diesel fuel. This included some refiners with relatively high costs of producing 15 ppm fuel. As described above, we did exclude 13 refineries with very high costs of producing 15 ppm fuel, and replaced their highway fuel with 15 ppm fuel produced from current high sulfur distillate fuel by four selected refineries. However, we did not include a few current "high sulfur" refineries which are projected to have the lowest cost of producing 15 ppm diesel fuel from high sulfur distillate fuel. We will reconsider this decision in the analysis for the final rule, as it may have increased the projected cost of 15 ppm highway diesel fuel and lowered the cost of producing 15 ppm nonroad diesel fuel to too great a degree. However, we do not expect this change to substantially change the average costs per gallon, as the total fuel volume affected by this decision is small.

With respect to the 500 ppm locomotive and marine diesel fuel cap in 2010, we project that 20 refiners would invest in new hydrotreaters to produce 500 ppm fuel, with 19 of these being small refiners. The reason most of these additional refiners would be small refiners is due to the expiration of the small refiner provisions related to 500 ppm NRLM diesel fuel. An additional 17 refineries would continue producing 500 ppm diesel fuel (which they started doing in 2007).

The costs of producing 500 ppm diesel fuel in 2010 are presented in Table 7.2-45. This fuel includes locomotive and marine diesel fuel, as well as 500 ppm nonroad diesel fuel produced by small refiners (or by other refiners purchasing small refiner credits). Of the 20 refineries which initially comply with the 500 ppm standard in year 2010, 17 refiners would install new hydro treaters and three "highway" refiners would modify their existing highway hydrotreater to process their high sulfur distillate fuel.

Table 7.2-45
Refining Costs for 500 ppm Diesel Fuel in 2010 ($2002, 7% ROI before taxes)

	All Refineries in 2010	New Refineries in 2010	Small Refineries
Number of Refineries	37	20	19
Total Refinery Capital Cost ($Million)	357	150	131
Average Refinery Capital Cost ($Million)	9.7	7.5	6.9
Average Refinery Operating Cost ($Million/yr)	5.3	1.6	0.9
Capital Cost (c/gal)	0.7	0.8	1.5
Operating Cost (c/gal)	1.6	1.6	1.8
Cost Per Affected Gallon (c/gal)	2.3	2.4	3.3

The average cost per gallon of producing 500 ppm fuel for the 20 new 500 ppm refineries is almost identical to that for the 17 refineries already producing 500 ppm fuel. However, small refiners would face costs roughly 40% higher than those of the average refiner producing 500 ppm fuel.

7.2.2.2.3 Refining Costs in Year 2014

15 ppm Nonroad Diesel Fuel: In 2014, small refiner provisions related to the 15 ppm nonroad diesel fuel cap expire, increasing the total required volume of 15 ppm nonroad diesel fuel. The total production volume of 500 ppm NRLM diesel fuel decreases to just that used in locomotives and marine vessels. The specific refineries producing the additional volume of 15 ppm nonroad diesel fuel were those facing the lowest projected costs per gallon in each PADD, plus some refineries which we projected would have difficulty distributing large volumes of 500 ppm locomotive and marine diesel fuel. The volume of combined 15 ppm and 500 ppm NRLM fuel in 2014 is the same as that in 2010.

We project that 12 additional refineries would produce 15 ppm nonroad diesel fuel in 2014, with 7 of these being refineries owned by small refiners. None of these refineries would install new hydrotreaters, as none were using their existing highway diesel hydrotreater to produce 500 ppm NRLM diesel fuel in 2007. Three “highway” refineries would incorporate their current high sulfur distillate fuel with their highway diesel fuel when they revamp their highway hydrotreater to produce 15 ppm highway diesel fuel in 2010. The remaining 9 refineries are projected to revamp their new nonroad hydrotreater built in 2007 to produce 500 ppm NRLM diesel fuel.

The refining costs to produce 15 ppm nonroad fuel in 2014 are presented in Table 7.2-46. The first two columns containing costs show the total and incremental refining costs for all refineries. The last two columns containing costs show the total and incremental refining costs for small refiners. Total refining costs are those relative to today's uncontrolled sulfur levels. Incremental costs are those relative to the cost of producing 500 ppm fuel in 2007 or 2010.

Table 7.2-46
Refining Costs for 15 ppm Nonroad Fuel for Refiners Initially Complying in 2014
($2002, 7% ROI before taxes)

	All Refineries		Small Refineries	
	Total	Incremental to 500 ppm	Total	Incremental to 500 ppm
Number of Refineries	12	12	7	7
Total Refinery Capital Cost ($Million)	256	163	161	86
Average Refinery Capital Cost ($Million)	21.3	13.6	23.0	12.23
Average Refinery Operating Cost ($Million/yr)	2.9	1.5	2.2	0.9
Capital Cost (c/gal)	2.4	1.5	4.4	2.3
Operating Cost (c/gal)	3.0	1.5	3.8	1.1
Cost Per Affected Gallon (c/gal)	5.3	3.0	8.2	3.9

The total refining cost to produce 15 ppm fuel is 5.3 cents per gallon, or 1.1 cent per gallon more than in 2010. The average incremental cost to desulfurize from 500 ppm to 15 ppm is 3.0 cents per gallon, or 0.9 cents per gallon higher than in 2010. Small refiners' average cost to produce 15 ppm nonroad diesel fuel 8.2 cents per gallon, or more than 50% higher than that of the average refiner. The average refinery first producing 15 ppm nonroad diesel fuel in 2014 faces a capital investment of $14 million, while the investment for the average small refiner would be only slightly smaller, $12 million.

The following two tables present the total and incremental refining costs for all 15 ppm nonroad diesel fuel being produced in 2014, after the expiration small refiner provisions. These costs include those for refiners first producing 15 ppm nonroad diesel fuel in 2010 and 2014.

Table 7.2-47
Total Refinery Costs for 15 ppm Nonroad Diesel Fuel in 2014
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	37	30	7
Total Refinery Capital Cost ($Million)	976	813	161
Average Refinery Capital Cost ($Million)	26.4	27.1	23.0
Average Refinery Operating Cost ($Million/yr)	5.0	5.7	2.2
Capital Cost (c/gal)	1.6	1.4	4.4
Operating Cost (c/gal)	2.8	2.7	3.8
Cost Per Affected Gallon (c/gal)	4.4	4.1	8.2

Table 7.2-48
Incremental Refinery Costs for All 15 ppm Nonroad Fuel in 2014
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	37	30	7
Total Refinery Capital Cost ($Million)	640	556	84
Average Refinery Capital Cost ($Million)	17.3	18.5	11.9
Average Refinery Operating Cost ($Million/yr)	2.0	2.6	1.0
Capital Cost (c/gal)	1.1	1.0	2.3
Operating Cost (c/gal)	1.1	1.2	1.7
Cost Per Affected Gallon (c/gal)	2.3	2.2	4.0

With full implementation of the 15 ppm nonroad diesel fuel cap, we project that 37 refineries would produce this fuel. The total refining cost measured from today's high sulfur level would be 4.4 cents per gallon, or 2.3 cents per gallon cost over that to produce 500 ppm fuel. Small refineries would have an average cost of 8.2 cents per gallon, or twice as high as the average non-small refineries. The average capital cost to produce 15 ppm nonroad fuel would be $23.0 million for the average small refiner, or $4 million less than the average non-small refinery. However, the amortized capital cost per gallon would be much higher for the average small refinery due to their lower production volumes.

500 ppm Locomotive and Marine Diesel Fuel: In 2014, the number of refineries producing 500 ppm fuel drops from 37 to 25, as no new volume of 500 ppm diesel fuel would be required and 12 refineries producing 500 ppm diesel fuel in 2010 shift to 15 ppm nonroad diesel fuel.

There is no new investment to produce 500 ppm diesel fuel, as all of the 500 ppm locomotive and marine diesel fuel being produced in 2014 was already being produced in 2010. The costs of the remaining 500 ppm diesel fuel being produced in 2014 are shown in Table 7.2-49.

Table 7.2-49
Refining Costs to Produce 500 ppm Locomotive and Marine Diesel Fuel in 2014
($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	25	12
Average Refinery Capital Cost ($Million)	10.6	4.5
Average Refinery Operating Cost ($Million/yr)	2.8	0.8
Capital Cost (c/gal)	0.6	1.0
Operating Cost (c/gal)	1.6	1.7
Cost Per Affected Gallon (c/gal)	2.2	2.7

The cost to produce 500 ppm diesel fuel in 2014 is 2.2 cents per gallon. This is a slight decrease from the cost in 2010 due a number of higher cost refineries (mostly owned by small refiners) exiting the 500 ppm market to make 15 ppm fuel. The average cost for small refiners still producing 500 ppm diesel fuel is only slightly greater than that for the average refinery, 2.7 cents per gallon.

7.2.2.2.4 Total Refining Costs at Different Rates of Return on Investment

We also estimated the total refining cost of the proposed NRLM fuel program using two alternative rates of return on investment: 1) 6% per year after taxes, and 2) 10% per year after taxes. The 6% rate is indicative of the economic performance of the refining industry over the past 10-15 years. The 10% rate is indicative of economic performance of an industry like refining which would attract additional capital investment. The total refining costs for both 500 and 15 ppm NRLM fuels once the proposed program is fully implemented in 2014 are shown below for our standard 7% before tax rate, and the two alternative rates. As can be seen, the difference in the rates of return on investment range from 0.1-0.8 cents per gallon.

Table 7.2-50
Total Refining Costs for the Fully Implemented Proposed NRLM Program with Different Capital Amortization Rates (cents per gallon, $2002)

	500 ppm Locomotive and Marine Diesel Fuel	15 ppm Nonroad Diesel Fuel
Societal Cost 7% ROI before Taxes	2.2	4.4
Capital Payback (6% ROI, after Taxes)	2.3	4.5
Capital Payback (10% ROI, after Taxes)	2.6	5.2

7.2.2.3 15 ppm Nonroad Diesel Fuel with Conventional Technology

The use of advanced technology is expected to reduce the cost of producing 15 ppm diesel fuel compared to conventional hydrotreating. To determine the sensitivity of our costs estimates to the level of advanced technology projected, we developed costs for producing 15 ppm nonroad diesel fuel with only the use of conventional hydrotreating.

Total refining costs to produce 15 ppm nonroad diesel fuel in 2014 are shown in Table 7.2-51. The number of refiners required to invest (37 refiners) and types of hydrotreating modifications are the same with conventional technology as described above for a mix of advanced and conventional technology. Total capital costs would be $983 million with conventional technology, essentially identical to the $976 million investment with advanced technology (see Table 7.2-40). However, operating costs would be nearly 40% higher with conventional technology, $6.9 million as compared to $5.0 million with advanced technology. The same comparison applies to the impact of advanced technology on the capital costs faced by small refiners. While the use of conventional technology increases operating costs for small refiners ($2.6 million per year versus $2.2 million per year with advanced technology), the reduction is smaller at just over 15%. This smaller benefit is due to their lower production volumes and lower fractions of LCO and other cracked stocks. The total cost to produce 15 ppm nonroad diesel fuel in 2014 with conventional technology would be 5.4 cents per gallon, versus 4.4 cents with a mix of conventional and advanced technology.

Table 7.2-51
Total Refining Costs to Produce 15 ppm Nonroad Diesel Fuel
with Conventional Technology in 2014 ($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	37	7
Total Refinery Capital Cost ($Million)	983	150
Average Refinery Capital Cost ($Million)	26.6	21.5
Average Refinery Operating Cost ($Million/yr)	6.9	2.6
Capital Cost (c/gal)	1.6	4.1
Operating Cost (c/gal)	3.8	4.5
Cost Per Affected Gallon Cost (c/gal)	5.4	8.5

The previous comparisons involved the total cost of producing 15 ppm diesel fuel from high sulfur diesel fuel. However, we are only projecting that the advanced technology would be applied to the step from 500 ppm to 15 ppm sulfur. Table 7.2-52 compares the refining costs of producing 15 ppm nonroad diesel fuel from 500 ppm diesel fuel using 100 percent conventional hydrotreating and with a mix of advanced and conventional technology.

Table 7.2-52
Impact of Advanced Technology on the Incremental Refining Costs
to Produce 15 ppm Nonroad Diesel Fuel ($2002, 7% ROI before taxes)

	Refineries Producing 15 ppm Fuel First in 2010		Refineries Producing 15 ppm Fuel First in 2014	
	Advanced and Conventional	Conventional Technology Only	Advanced and Conventional	Conventional Technology Only
Average Capital Cost ($Million)	19.1	19.4	13.6	12.7
Operating Cost ($Million/yr)	2.6	5.4	1.5	2.11
Capital Cost (c/gal)	0.9	0.9	1.5	1.4
Operating Cost (c/gal)	1.2	2.5	1.5	2.1
Cost Per Gallon (c/gal)	2.1	3.4	3.0	3.5

For refiners that first produce 15 ppm nonroad diesel fuel in 2010, the projection that 80 percent would use advanced technology versus conventional technology decreases incremental refining costs relative to 500 ppm fuel by 1.4 cents per gallon, or more than 25%. Capital costs decrease only slightly, while operating costs decrease by more than 50%.

For refiners that first produce 15 ppm nonroad diesel fuel in 2014, the projection that 100 percent would use advanced technology versus conventional technology decreases incremental refining costs relative to 500 ppm fuel by 0.5 cents per gallon, or roughly 15%. Capital costs actually increase, while operating costs decrease by roughly 30%. The lower savings occurring in 2014 relative to 2010 are due to the relative volumes of distillate being desulfurized at each refinery and the percentages of LCO and other cracked stocks at the refineries producing 15 ppm fuel in the two timeframes.

7.2.2.4 Refining Costs for Alternative NRLM Fuel Programs

7.2.2.4.1 One Step NRLM Fuel Program in Year 2008

This one step program specifies that nonroad diesel fuel would have to meet a sulfur cap of 15 ppm starting on June 1, 2008, while locomotive and marine diesel fuel would have to meet a 500 ppm cap at the same time. Small refiners would have four more years before having to meet these standards. In the meantime, small refiners could sell high sulfur diesel fuel to the NRLM fuel markets.

Once fully implemented, the same refineries would produce the same 15 and 500 ppm NRLM diesel fuels as those projected under the proposed NRLM fuel program. Still, moving up the 15 ppm nonroad diesel fuel cap by two years would increase costs in two ways. One, the cost of 15 ppm nonroad fuel would be incurred two years earlier. That effect is addressed in Chapter 12, where aggregate costs are estimated for the various alternatives. Two, the cost of producing 15 ppm nonroad fuel would increase, as the earlier implementation date is projected to reduce the penetration of advanced desulfurization technology. As described in section 7.2.1 above, we project that refiners would use a mix of 60 percent conventional and 40 percent advanced technology to produce 15 ppm diesel fuel in 2008, as compared to a 20/80 mix in 2010. Fifteen ppm diesel fuel initially produced in 2012 would be desulfurized using 100 percent advanced technology, as was projected for 2014. Cost are only presented for the fully implemented program in 2012.

We project that 62 refineries would produce 500 ppm locomotive and marine diesel fuel or 15 ppm nonroad diesel fuel in 2012, when the program would be fully implemented. The total refining costs for the one step fuel program are shown in Table 7.2-53. The total refining cost for the one step fuel program for 15 ppm nonroad fuel would be 4.8 cents per gallon, or 0.4 cents per gallon more than that for nonroad fuel cost in the proposed two step program. The total capital cost of the one step program would also exceed those of the proposed two step program by $55 million.

Table 7.2-53
Total Refining Cost to Produce 15 ppm Nonroad Diesel Fuel
Under One Step Program ($2002, 7% ROI before taxes)

	One Step Program	Proposed Program
Number of Refineries	37	37
Total Refinery Capital Cost ($Million)	1,031	976
Average Refinery Capital Cost ($Million)	27.9	26.4
Average Refinery Operating Cost ($Million/yr)	5.6	5.0
Cost Per Affected Gallon Cost (c/gal)	4.8	4.4

The cost of the 500 ppm locomotive and marine diesel fuel under the one step pro gram would not differ from that under the proposed two step program, as the same refineries using the same conventional hydrotreating are projected to be used in both cases. The difference in total costs of the two programs lies in the production of 15 ppm nonroad diesel fuel.

7.2.2.4.2 Proposed Two Step NRLM Fuel Program with Nonroad 15 ppm Cap in 2009

This program would be identical to the proposed NRLM fuel program except for one difference: the 15 ppm nonroad sulfur cap would be implemented one year earlier. The 500 ppm sulfur standard for nonroad, locomotive and marine would still begin in mid-2007. Small refiners would be able to sell high sulfur diesel fuel to the NRLM markets until mid-2009, and would be able to sell 500 ppm diesel fuel to the nonroad market until mid-2013.

Moving up the 15 ppm nonroad diesel fuel cap by one year would increase costs in two ways. One, 15 ppm nonroad fuel would be incurred one year earlier. That effect is addressed in Chapter 12, where aggregate costs are estimated for the various alternatives. Two, the cost of producing 15 ppm nonroad fuel would increase due to the earlier implementation date. The 37 refineries planning to produce 15 ppm nonroad diesel fuel in 2009 would only be producing 500 ppm NRLM fuel for two years. Thus, we projected that they would fully construct their 15 ppm desulfurization equipment in 2007. This moved up the capital needed to meet the 15 ppm cap by one year, increasing amortized costs per gallon of 15 ppm fuel produced. It also reduced the projected penetration of advanced desulfurization technology. Specifically, we project that 60% of the volume of 15 ppm fuel would be produced using advanced technology with a 2007 construction date, compared to the 80% level a year later. Small and other refiners first producing 15 ppm fuel in 2013 would be all projected to use 100 percent advanced technology.

The cost of the 500 ppm locomotive and marine diesel fuel cap would not be affected by moving up the 15 ppm cap one year, as the same refineries using conventional hydrotreating are projected to be used in both programs. The difference in total costs of the two programs lies in the production of 15 ppm nonroad diesel fuel. Thus, we have summarized the costs of producing 15 ppm nonroad diesel fuel in Table 7.2-54. Overall, the same refineries are projected to produce

15 ppm nonroad diesel fuel. While total capital costs are essentially identical, operating costs increase relative to the proposed two step program by 10% and per gallon costs increase by 5%.

Table 7.2-54
Total Refining Costs for 15 ppm Nonroad Fuel Under a
Two Step Program with the 15 ppm Standard in 2009 ($2002, 7% ROI before taxes)

	Two Step Program with 15 ppm in 2009	Proposed Two Step Program
Number of Refineries	37	37
Total Refinery Capital Cost ($Million)	977	976
Average Refinery Capital Cost ($Million)	26.4	26.4
Average Refinery Operating Cost ($Million/yr)	5.5	5
Cost Per Affected Gallon Cost (c/gal)	4.6	4.4

7.2.2.4.3 Proposed Two Step Program with a 15 ppm Cap for Locomotive and Marine Fuel in 2010

This program would be identical to the proposed NRLM fuel program except for one difference: the 15 ppm nonroad sulfur cap would be extended to locomotive and marine diesel fuel. The 500 ppm sulfur standard for nonroad, locomotive and marine would still begin in mid-2007. Small refiners would be able to sell high sulfur diesel fuel to the NRLM markets until mid-2010, and would be able to sell 500 ppm diesel fuel to the NRLM market until mid-2014.

The cost of the 500 ppm locomotive and marine diesel fuel cap in 2007 would not be affected by moving up the 15 ppm cap one year, as the same refineries using conventional hydrotreating are projected to be used in both programs. The difference in total costs of the two programs lies in the increased production of 15 ppm nonroad diesel fuel in 2010 and 2014. The total costs of producing NRLM diesel fuel for both the proposed program and that with the 15 ppm cap for locomotive and marine diesel fuel are shown in Table 7.2-55.

Table 7.2-55
Total Refining Costs for Two Step Program:
All NRLM Fuel to 15 ppm in 2010 ($2002, 7% ROI before taxes)[a]

	One Step Program	Proposed Program
Number of Refineries	62	62
Total Capital Cost ($Million)	1,720	1,240
Average Capital Cost per Refinery ($Million)	27.7	20.0
Average Refinery Operating Cost ($Million/yr)	4.9	4.1
Cost Per Affected Gallon Cost (c/gal)	4.6	4.1

[a] Fully implemented program in 2014.

Overall, the same refineries are projected to be affected. The difference is that refineries producing 500 ppm locomotive and marine diesel fuel in 2014 under the proposed program now produce 15 ppm diesel fuel. Extending the 15 ppm cap to locomotive and marine diesel fuel increases total capital cost by $480 million. The total cost per gallon of fuel affected would increase by 0.5 cent per gallon, or just over 10%. The cost of 15 ppm diesel fuel would increase from to 4.6 from 4.4 cents per gallon, or just 5%. However, this approach spreads out the increased costs of extending the 15 ppm cap to greater fuel volume of all NRLM diesel fuel volume. The cost of the 15 ppm locomotive and marine diesel fuel would be 4.8 cents per gallon, or about 10% greater than the 15 ppm nonroad diesel fuel.

7.2.2.5 Capital Investments by the Refining Industry

Refiners must raise capital to invest in new desulfurization equipment to produce the 500 ppm and 15 ppm diesel fuel which would be required under the proposed NRLM fuel program. The previous sections estimated the total capital cost associated with the proposal and two alternative programs. Refiners expend this capital over a several year period prior to the time which the new equipment must be used. This section estimates how much capital would have to be expended in specific years under the proposal and two alternative programs. These yearly expenditures are then added to those required by other fuel quality programs being implemented in the same timeframe and compared to historic capital expenditures made by the refining industry.

Two fuel quality regulations are being implemented in the same timeframe as this proposed NRLM fuel program: The Tier 2 gasoline sulfur program and the 2007 highway diesel fuel sulfur program. In the Tier 2 gasoline sulfur control rule, we estimated the expenditure of capital for gasoline desulfurization by year according to the phase in schedule promulgated in the rule.[j] The

[J] Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: The Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, 2007 highway diesel rule modified that phase in schedule by provided certain refiners more time to meet the Tier 2 gasoline sulfur standards. In the 2007 highway diesel rule, we projected the stream of capital investments required by the U.S. refining industry for both the modified Tier 2 standards and the 15 ppm highway diesel fuel sulfur program. We updated the total capital costs associated with the 2007 highway diesel fuel program, as discussed in section 7.2.2.1 above. In projecting the stream of capital expended for a particular project, we assume that the capital investment would be spread evenly over a 24 month period prior to the date on which the unit must be on-stream. The stream of projected capital investment related to the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program rule are shown in Table 7.2-56.

Table 7.2-56
Capital Expenditures for Gasoline and Highway Diesel Fuel Desulfurization
($Billion, $2002)[a]

Calendar Year	Tier 2 Gasoline Sulfur Program	2007 Highway Diesel Program	Total
2002	1.76		1.76
2003	1.15		1.15
2004	0.88	1.33	2.21
2005	0.61	2.15	2.76
2006	0.16	0.82	0.98
2007	0.06		0.06
2008	0.06	0.41	0.47
2009	0.02	0.62	0.64
2010		0.21	0.21

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

The two diesel fuel programs have implementation dates of June 1 of various years for fuel leaving the refinery. For this start up date, we assumed that 30% of the capital cost was expended in the calendar year two years prior to start up, 50% was expended in the year prior to start up and the remaining 20% was expended in the year of start up. We repeated this analysis for the one step NRLM program and the proposed NRLM program with 15 ppm cap for locomotive and marine diesel fuel. The results are summarized in Table 7.2-57 below.

December 1999, EPA 420-R-99-023. Adjusted to 2002 dollars using Chemical Engineering Plant Cost Index.

Table 7.2-57
Capital Expenditures for NRLM Fuel Programs with
Tier 2 Gasoline Sulfur and 2007 Highway Diesel Fuel Programs ($Billion, $2002)

Calendar Year	Proposed Two Step NRLM Fuel Program		Proposed Program + Locomotive and Marine to 15 ppm in 2010		One Step NRLM Program in 2008	
	Increment	Total[a]	Increment	Total[a]	Increment	Total[a]
2002		1.76		1.76		1.76
2003		1.15		1.15		1.15
2004		2.21		2.21		2.21
2005	0.14	2.90	0.14	2.90		2.76
2006	0.23	1.21	0.23	1.21	0.31	1.29
2007	0.09	0.15	0.09	0.15	0.52	0.58
2008	0.19	0.66	0.32	0.79	0.21	0.68
2009	0.31	0.95	0.54	1.18	0.64	0.64
2010	0.13	0.34	0.22	0.43	0.08	0.29
2011					0.13	0.13
2012	0.05	0.05	0.54	0.54	0.05	0.05
2013	0.08	0.08	0.91	0.91		
2014	0.03	0.03	0.36	0.39		

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

As can be seen, capital investments peak in 2005 for all NRLM programs. The proposed two step NRLM program increases this peak by $140 million, or about 5%. Thereafter, capital requirements drop dramatically. The proposed two step NRLM program with a 15 ppm cap on locomotive and marine diesel fuel would require the same capital investments increases through 2007. Thereafter, it causes increased capital requirements, but this is well after the peak investment requirements have occurred. The one step NRLM fuel program avoids increasing capital investment in 2005, but more than makes up for this in 2006, though at a lower total investment for all three programs. In all cases, the vast majority of capital investment in the 2002-2006 timeframe, when capital investment requirements are the highest, are causes by the Tier 2 gasoline sulfur and 2007 highway diesel fuel programs. In comparison, the capital investment requirements for the proposed NRLM fuel program are much smaller and more spread out.

Estimates of previous capital investments by the oil refining industry for the purpose of environmental control are available from two sources: the Energy Information Administration

(EIA) and the American Petroleum Institute (API). According to EIA, capital investment by the 24 largest oil refiners for environmental purposes peaked at $2 billion per year during the early 1990's.[k] Total capital investment by refiners for other purposes was in the $2-3 billion per year range during this time frame. API estimates somewhat higher capital investments for environmental purposes, with peaks of about $3 billion in 1992-1993.[l] Based on these two sources, during the early 90's, the US refining industry invested over 20 billion dollars in capital for environmental controls for their refining and marketing operations, representing about one half of the total capital expenditures made by refiners for operations.

The capital required for the Tier 2 gasoline, 2007 highway diesel fuel and the proposed NRLM fuel program is about two-thirds of the historic peak level of investment for meeting environmental programs experienced during 1992-1994.[46] Given that the capital required by the proposed NRLM fuel program contributes only 5% to the required investment in the peak year of 2005, we do not expect that the industry would have difficulty raising this amount of capital.

7.2.2.6 Other Cost Estimates for Desulfurizing Highway Diesel Fuel

For the Engine Manufacturers Association and with input by the American Petroleum Institute, Mathpro used a notional refinery model to estimate the national average costs of desulfurizing nonroad diesel fuel after the implementation of the 15 ppm cap standard for highway diesel fuel. The cost estimate from this study is presented here and compared to our costs.

In a study conducted for the EMA,[47,48] MathPro, Inc. first estimated the cost of desulfurizing diesel fuel to meet a 15 ppm highway diesel fuel sulfur cap standard followed by a two step nonroad standard of caps of 500 ppm and 15 ppm. MathPro assumed that desulfurization would occur entirely with conventional hydrotreating, and refining operations and costs were modeled using their ARMS modeling system with technical and cost data provided by Criterion Catalyst Company LP, Akzo-Nobel Chemicals Inc., and Haldor Topsoe, Inc. The Mathpro refinery model estimated costs based on what Mathpro terms a “notional” refinery. The notional refinery is configured to be typical of the refineries producing highway diesel fuel for PADDs 1, 2, and 3, and also represent the desulfurization cost for those three PADDs based on the inputs used in the refinery model. The Mathpro notional refinery model maintained production of highway diesel fuel at their base levels.

Mathpro made a number of estimates in their study to size their diesel desulfurization units for estimating the capital cost, and these estimates were similar to those included in our methodology. The calendar day volume was adjusted to stream day volume using a 10 percent factor to account for variances in day-to-day operations, and another 10 percent to account for

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[K] Rasmussen, Jon A., “The Impact of Environmental Compliance Costs on U.S. Refining profitability,” EIA, October 29, 1997.

[L] API Reported Refining and Marketing Capital Investment 1990-1998.

variance in seasonal demand. In addition, Mathpro applied a factor which falls somewhere in the range of 1 - 8 percent for sizing the desulfurization unit larger for reprocessing off-spec material to meet a number of different sulfur targets. Since meeting a 500 ppm cap standard is not very stringent, Mathpro likely assumed that a desulfurization unit would need to be sized larger by 1 - 4 percent. For meeting the 15 ppm cap standard which is a relatively stringent sulfur standard compared to the 500 ppm sulfur level studied, Mathpro likely assumed the desulfurization unit would be sized larger by 5 - 8 percent. Onsite investment was adjusted to include offsite investment using a factor of 1.4. In the final report, capital costs were amortized at a 15 percent after tax rate of return.

The Mathpro cost study analyzed the costs to comply with the highway program based on 5 different investment scenarios. Before deriving the best nonroad desulfurization cost estimate using the Mathpro cost study, we must describe the various investment scenarios. The titles of the scenarios are listed here:

1. No Retrofitting - Inflexible
2. No Retrofitting - Flexible
3. Retrofitting - De-rate/Parallel
4. Retrofitting - Series
5. Economies of Scale

Scenarios 1 and 2 do not allow retrofitting which means that the existing highway diesel hydrotreater must be removed from service and an new grassroots unit takes its place which desulfurizes untreated distillate down to under 15 ppm. The difference between scenarios 1 and 2 is that scenario 1 does not allow some flexibilities which may be available to the refining industry. One flexibility is that the volume of hydrocracker units is not limited to the used capacity as listed in the 1997 API/NPRA survey, but instead the throughput can be as much as 8 percent higher which is half the available capacity available in the API/NPRA survery. Another flexibility is that jet fuel exceeds specifications and instead of limiting the qualities to current levels, they are instead allowed to become heavier by 0.5 API or by 3 points on the E375 distillation curve and stay within the jet fuel specifications. Allowing jet fuel to get heavier allows the refinery model to bring some of these lighter jet fuel blendstocks into the highway diesel fuel pool which lowers the desulfurization cost. The flexibilities are allowed in the rest of the scenarios as well.

Scenarios 3 and 4 allow taking advantage of the existing highway desulfurization unit by keeping it in place and installing additional capital including additional reactor volume which allows the combined used and new capital to achieve the 15 ppm cap standard. The difference between scenarios 3 and 4 is that Scenario 3 derates the existing hydrotreater which reduces the volume treated by that unit so that it can achieve 15 by itself and then another unit is added in parallel which is also being fed by a low throughput which allows it to meet the 15 ppm cap standard. Scenario 4 installs the new capital in series with the existing hydrotreater with both units handling the entire feed rate.

Scenario 5 allows the debottlenecking of existing capacity to treat a larger volume while producing the same specifications. Scenario 5 also allows a single unit to be installed to handle the desulfurization of multiple refineries in refining centers which provides an important economy of scale for the desulfurization investment costs to that group of refineries.

While these various investment scenarios were devised to understand how different investment scenarios would affect the cost for the highway rule, they have implications for the nonroad rule as well. For meeting a 500 ppm cap nonroad diesel fuel standard, the used highway units which are freed up in Scenarios 1 and 2 can thus be converted over to nonroad service which dramatically reduces the capital cost of compliance, and this supplements the existing nonroad capacity which is already in place. However, for Scenario 2, the installed grassroots capacity installed for the highway rule decreased after the capital was already installed and a larger volume of existing hydrotreating capacity removed from highway desulfurization service was put into place to supplement the nonroad hydrotreating capacity already in place. For Scenario 3, the needed nonroad capacity is formed by adding grassroots capacity. For Scenario 4, the necessary nonroad hydrotreating capacity is formed by increasing the existing unit capacity used, relying on some expansion of existing units and adding some processing unit capacity in series with existing capacity. The nonroad hydrotreating capacity for meeting the 500 ppm cap standard is realized for Scenario 5 similar to Scenario 4, except no expansion of existing units occurs, but instead more capacity from existing highway units is relied upon.

For meeting the 15 ppm cap sulfur standard for nonroad diesel fuel, the refinery model invested in nonroad capital either along the same lines as the 500 ppm case, or else invested much differently. For Scenario 1 and 2, the refinery model installed grassroots units only, even replacing some existing hydrotreating capacity which was likely being used for some mild desulfurization of nonroad diesel fuel. For Scenario 2, the volume of grassroots desulfurization capacity was slightly lower than Scenario 1 probably due to the increased flexibility which the refinery model was granted. For Scenario 3, the refinery model added some new grassroots unit capacity compared to the 500 ppm case, probably derating the capacity of the remaining 500 ppm and new 500 ppm capacity. For Scenario 4, the refinery model added more series unit capacity and more expansion capacity. Finally for Scenario 5, the refinery model increased the series processing unit capacity and added some expansion capacity.

The new or existing hydrotreating capacity used for meeting the 500 ppm and 15 ppm nonroad standards incremental to meeting the highway 15 ppm sulfur standard is shown in Table 7.2-58.

Table 7.2-58
Mathpro Capital Costs for Desulfurizing Highway and Nonroad Diesel Fuel

		No Retr Inflex	No Retr Flex	Retr De-rate	Retr Series	Econ of Scale
Reference Case	Existing Cap	34.9	34.9	34.9	34.9	34.9
Highway 15 ppm Cap Std	Existing Unit	8.2	8.2		31.1	31.1
	Expansion					
	De-rated			17.8		
	Series Unit			15.4	29.4	29.4
	Grassroot Unit	30.2	29.3			
Nonroad Meeting a 500 ppm Cap Standard	Existing Unit	16.5	19.4		35.0	38.0
	Expansion				2.9	
	De-rated			17.8		
	Series Unit				34.1	34.0
	Grassroot Unit	30.1	27.6	23.7		
Nonroad Meeting a 15 ppm Cap Standard	Existing Unit				35.0	38.0
	Expansion				4.9	1.9
	De-rated			17.8		
	Series Unit				39.1	39.1
	Grassroot Unit	50.4	49.3	26.5		

We next needed to determine which of the Mathpro cases which would best approximate the investment scenarios which we are using in our 500 ppm cost analysis. As described above in this section, the refineries which comply with the highway rule in 2006 by putting in a new hydrotreater (20 percent of the mixed highway and nonroad refineries which comply with the highway requirements in 2006 and which have a distillate hydrotreater), thus idling the existing hydrotreater, is projected to use the existing hydrotreater to produce 500 ppm sulfur nonroad diesel fuel in 2007. Those refineries comprise 7 percent of the nonroad pool. The rest of the refineries are expected to install a new unit in 2007 to comply with the 500 ppm sulfur standard. Next, we examined the Mathpro investment cases to match them with the scenarios in our cost analysis. There were no cases which matched our scenario exactly, but we found two Mathpro cases which, together, matched our investment scenario. The first is the No Retrofit Inflexible case which met the nonroad requirements exclusively through using existing capacity. The second case is the retrofitting derating case which met the nonroad requirements through new capital investment. Since our analysis had only 9 percent of the nonroad volume as being produced by refineries which would use the existing hydrotreater to produce 500 ppm sulfur nonroad diesel fuel, the Mathpro costs were weighted 7 percent No Retrofit Inflexible costs and 93 percent and Retrofit DeRate costs.

We then examined the Mathpro 15 ppm cases to determine which of them best matched our 15 ppm scenario. Since we already have identified the Mathpro cases for estimating the incremental cost for going from meeting the 500 ppm standard to meeting the 15 ppm sulfur standard, we needed to consider how to adjust the costs to remove any costs associated with going from untreated to 500 ppm. As discussed above in this section, our 15 ppm scenario has new nonroad diesel fuel hydrotreating units being installed in 2010, although those which are mixed highway and nonroad refineries are expected to install their highway and nonroad units together taking advantage of the economies of scale for doing so. Of the Mathpro cases summarized above, the first two cases, which don't allow revamps and either allow or don't allow operational flexibility, install grassroots units for obtaining the 15 ppm standard. Since the second Mathpro case apparently allowed backsliding in the highway grassroots units needed for complying with the highway rule when the 500 ppm standard was being met which we don't think is possible because the highway investments will be too far along before the nonroad program is finalized, we decided to use Mathpro's case one.

Case one, however, needed to be adjusted to develop a scenario which we believe is more realistic based on how refiners are likely to comply with the highway and nonroad programs. Mathpro's case one was associated with the replacement of the existing hydrotreating capacity which was likely used for desulfurizing nonroad down to 500 ppm. However, we believe that 80 percent of the existing nonroad desulfurization capacity can be revamped instead of having to be replaced. Thus, we adjusted the Mathpro capital costs to remove the extra grassroots hydrotreating capacity. We accomplished this by estimating what percent of the capital costs is necessary for complying with 15 ppm standard and for replacing the expected portion of existing nonroad desulfurization capital. The nonroad diesel fuel volume needed to be treated in Mathpro's notional refinery model is 9 thousand barrels per day. According to Mathpro, the capital needed to be installed to treat the nonroad pool down to 15 ppm is increased by 10 percent to handle peak throughput rates, and then by another 10 percent to handle peak seasonal rates and then by another 8 percent to handle reprocessing of off-spec batches. Thus the 9,000 barrels per day nonroad volume is increased to about 11,800 barrels per day which represents Mathpro's estimated capital capacity. We subtracted 11,800 bpd from the total volume of grassroots capacity added, which was 20,300 bpd, to yield a total of 8,500 barrels per day of replaced capital capacity which we assumed would be untreated to 500 ppm nonroad hydrotreated capacity. Since we believe that it is reasonable that 20 percent of this existing capacity would be replaced, we maintained 20 percent of 8,500 bpd, or an additional 1,700 barrels of the new nonroad hydrotreating capacity. Therefore, we maintained 13,500 bpd of the original 20,300 bpd of additional capacity added in Mathpro case one. To estimate a revised cost for Mathpro's case one we multiplied the capital charge by a ratio of 13,500/20,300. No adjustment was necessary for the variable operating cost.

In addition to the differences and adjustments as described above, there are several other differences between our cost analysis and the cost analysis made by Mathpro which deserve mentioning or which were adjusted. First, the MathPro costs as reported in their final report are based on a 15 percent return on investment (ROI) after taxes. As stated above, our costs are calculated based on a 7 percent ROI before taxes, so to compare our cost analysis with the cost analysis made by Mathpro, we adjusted the Mathpro costs to reflect the rate of return on capital investment which we use. Second, the MathPro estimate includes a cost add-on (called an ancillary cost) for reblending and reprocessing offspec diesel fuel or for storing nontreated diesel fuel. While this is conceptually an appropriate adjustment, it appears that some of the reblending costs in the MathPro study appear to be transfer payments,[m] not costs. Third, MathPro assumed that all new hydrogen demand is met with new hydrogen plants installed in the refinery, which does not consider the advantage of hydrogen purchased from a third party which can be produced cheaper in many cases. As a result, their hydrogen cost may be exaggerated, which would tend to increase costs. Finally, it should be noted that the MathPro study did take into consideration the need for lubricity additives, but did not address costs that might be incurred in the distribution system. Thus, in a comparison of our costs with Mathpro's, we will include our cost estimate for adding the appropriate amount of lubricity additive, but not add on the distribution costs. For comparing the aggregate capital costs, the Mathpro aggregate capital costs for the cases which were chosen were adjusted using the undesulfurized nonroad, locomotive and marine diesel fuel volumes for 2007 and for undesulfurized nonroad diesel fuel for 2010. The undesulfurized volumes which we used for making the adjustments are presented in Section 7.1 of the draft RIA. A comparison of Mathpro's costs and our costs to desulfurize highway diesel fuel to meet a 500 ppm sulfur cap standard and then a 15 ppm sulfur cap standard is shown below in Table 7.2-59.

Table 7.2-59
Comparison of Mathpro's and EPA's
Refining Costs for Meeting a 500 ppm and a 15 ppm Nonroad Diesel Fuel Sulfur Cap Standard (7% ROI before taxes, no lubricity additive costs nor distribution costs included)

Fuel Standard	Type of Cost	Mathpro's Costs	EPA's Costs	
		No Advanced Tech	Advanced Tech in 2010	No Advanced Tech
500 ppm Cap Std.	Per-gallon Cost (c/gal)	2.5	2.2	2.2
	Total Capital Cost (billion$)	925	612	612
15 ppm Cap Std. Incremental to 500 ppm Std.	Per-gallon Cost (c/gal)	3.3	2.2	3.3
	Total Capital Cost (billion$)	836	649	606
Uncontrolled to 15 ppm	Per-gallon Cost (c/gal)	5.8	4.4	5.5
	Total Capital Cost (billion$)	1761	1261	1218

[M] A transfer payment is when money changes hands, but no real resources (labor, natural resources, manufacturing etc.) are consumed.

7.3 Cost of Distributing Non-Highway Diesel Fuel

7.3.1 Distribution Costs Under the 500 ppm Sulfur Non-Highway Diesel Fuel Program

7.3.1.1 Fuel Distribution-Related Capital Costs Under the 500 ppm Sulfur Non-Highway Diesel Fuel Program

The potential capital costs associated with distributing 500 ppm sulfur non-highway diesel fuel pertain to the need for additional product segregation which might result. Section 5.4.2 of this draft RIA evaluates the potential for additional product segregation in each segment of the distribution system. The projected capital costs associated with distribution non-highway diesel fuel meeting the proposed 500 ppm standard are limited to the need for approximately 1,000 bulk plants to add an additional storage tank and demanifold their delivery truck to handle an additional diesel product.

In its comments to the government/industry panel convened in accordance with the Small business Regulatory enforcement Act (SBRFA), the Petroleum Marketers Association of America (PMAA) stated that depending on the location, the cost of installing a new diesel storage tank at a bulk plant would range from $70,000 to $100,000. To provide a conservatively high estimate of the cost to bulk plant operators, we used an average cost of $90,000. This is consistent with the information we obtained from a contractor working for EPA (ICF Kaiser) on the installed cost of a 20,000 gallon diesel storage tank which is the typical tank size at bulk plant facilities. Demanifolding of the bulk plant operators delivery truck involves installing an internal bulkhead to make two tank compartments from a single compartment. To help control contamination concerns, we also estimated that an additional fuel delivery system would be installed on the tank truck(i.e. so that there would be a separate delivery system for each fuel carried by the delivery truck). The cost of demanifolding a tank truck and installing a an additional fuel delivery system is estimated at $10,000, of which $6,000 is the cost of installing a new fuel delivery system.[49] Thus, the cost to each of the affected bulk plants would be $100,000 for a total cost of $100,000,000.

Amortizing the capital costs over 20 years, results in a estimated cost for tankage at such bulk plants of 0.1 cent per gallon of affected non-highway diesel engine fuel supplied. Twenty years was chosen due to the very long life of fuel storage tanks, and their lack of obsolescence. Although the impact on the overall cost of the proposed program is small, the cost to those bulk plant operators who need to put in a separate storage tank may represent a substantial investment. Thus, we believe many of these bulk plants could make other arrangements to continue servicing both heating oil and NRLM markets. In some cases, two or more bulk plants within a given service area may a have a single owner. In these cases, the bulk plant operator could continue to serve both markets by storing heating oil at one facility and nonroad fuel at the other. However, it would be more likely that multiple bulk plants serving a given geographic area would have different owners. In such cases, exchange agreements could be worked out between the two bulk plant operators so that they could continue to serve both markets.

7.3.1.2 Distribution Costs Due to the Reduction in Fuel Volumetric Energy Content Under the Proposed 500 ppm Sulfur Diesel Fuel Program

We estimate that desulfurization of non-highway diesel fuel to meet the proposed 500 ppm sulfur standard would result in a 0.7 percent reduction in the volumetric energy content (VEC) of the affected fuel (see section 5.9.2 of this draft RIA). This increases the cost to distribute diesel fuel due to the increased volume.

We believe that the difference between the price of non-highway diesel fuel to end-users and the price to resellers provides an appropriate estimate of the cost of distributing non-highway diesel fuel. The Energy Information Administration (EIA) publishes data regarding the price excluding taxes of high-sulfur #2 diesel fuel to end-users versus the price to resellers. We used the five year average of the difference between these two prices to arrive at an estimated typical cost of distributing non-highway diesel fuel to the end-user of 10 cents per gallon. The following table (7.3-1) presents the EIA data that we used in estimating the cost of distributing non-highway diesel fuel.

Table 7.3-1
Cost of Distributing High-Sulfur #2 Diesel Fuel[a]
(cents per gallon, excluding taxes)

Year	Sales to End Users	Sales to Resellers	Difference Between Sales to End Users & Sales to Resellers
1995	52.4	61.4	9.0
1996	63.9	73.2	9.3
1997	60.2	69.8	9.6
1998	43.7	55.5	11.8
1999	51.9	62.0	10.1
5 Year Average	54.4	64.4	10.0

[a] Energy Information Administration, Annual Energy Review 2001

We assumed that the current 10 cent per gallon cost of distributing diesel fuel would stay constant. For example, a one percent increase in the amount of fuel distributed would increase total distribution costs by one percent. Thus, the 0.7 percent reduction in VEC is estimated to result in a 0.07 cents per gallon increase in the cost to distribute non-highway diesel fuel. This cost was applied to the gallons of non-highway diesel fuel that would need to be desulfurized to meet the proposed 500 ppm sulfur standard. This cost was applied to NRLM from June 2007 through June 2010 when the proposed 15 ppm sulfur standard for nonroad diesel fuel would be implemented. After June 2010, this cost applies to LM fuel only. The additional costs associated with the further reduction in nonroad diesel fuel VEC associated with desulfurization to meet a 15 ppm sulfur specification are discussed in section 7.3.2.2 of this draft RIA.

Since the difference in price at the refiner rack versus that at retail also includes some profit for the distributor and retailer, its use provides a conservatively high estimate of distribution costs. The fact that a slightly less dense (lighter, less viscous) fuel would require slightly less energy to be distributed also indicates that this estimate is conservative.

7.3.1.3 Other Potential Distribution Costs Under the Proposed 500 ppm Sulfur Diesel Fuel Program

We anticipate that there would be no other significant distribution costs associated with the adoption of the proposed 500 ppm non-highway diesel sulfur standard beyond those described in sections 7.3.1.1 & 2 above. As discussed in section 5.4 of this draft RIA, we do not expect the need for additional storage tanks beyond that discussed in section 7.3.1.2 above, an increase in pipeline downgrade or transmix volumes, or the need for additional facilities at the refinery to comply with the proposed fuel marker requirements.

Bulk plant and tank truck who previously only handled high-sulfur diesel fuel would need to begin observing practices to limit sulfur contamination during the distribution of 500 ppm diesel fuel. However, these practices are well established and are primarily associated with purging storage tanks and fuel delivery systems of high-sulfur diesel fuel prior to the use in handling 500 ppm diesel fuel. Such tasks can be readily accomplished. Training of employees would be necessary to impress the importance of consistently and carefully observing the practices to limit sulfur contamination. However, we estimate the costs associated would be minimal. In addition, we are estimating that most of the affected bulk plant operators would install dedicated storage tanks and truck delivery systems. This would obviate the need for much of the cautionary actions necessary to limit sulfur contamination when both low and high sulfur diesel fuel is carried by the same marketer.

7.3.2 Distribution Costs Under the 15 ppm Sulfur Nonroad Diesel Fuel Program

7.3.2.1 Fuel Distribution-Related Capital Costs Under the 15 ppm Sulfur Nonroad Diesel Fuel Program

As discussed in section 5.6 of this draft RIA, we do not anticipate that the implementation of the proposed 15 ppm sulfur standard would result in the need for fuel distribution industry to make changes that would require investment capital. Specifically, we project that there would be no substantial need for additional storage tanks or other facility changes to ensure product segregation.

7.3.2.2 Distribution Costs Due to the Reduction in Fuel Volumetric Energy Content Under the 15 ppm Sulfur Nonroad Diesel Fuel Program

We project that desulfurizing diesel fuel to 15 ppm would reduce volumetric energy content of the affected fuel by an additional 0.35 percent in addition the 0.7 percent reduction in VEC which accompanied desulfurization to meet the proposed 500 ppm standard. Thus, the total reduction in the VEC of nonroad diesel fuel which would need to be desulfurized to meet the proposed 15 ppm standard would be 1.1 percent (see section 5.9.2).

The methodology described in 7.3.1.2. for the calculation of the increase in distribution costs due to the reduction in VEC associated with meeting the proposed 500 ppm sulfur standard is also applicable in calculating the increase in distribution costs associated with meeting the proposed 15 ppm nonroad standard. Using this methodology, we estimate that the additional 0.35 percent reduction in the VEC of nonroad diesel fuel would increase the cost of distributing the affected gallons of 15 ppm nonroad diesel fuel by an additional 0.04 cent per gallon. Thus, the total increase in distribution costs associated with the decrease in VEC of 15 ppm nonroad diesel fuel would be 0.11 cent per gallon of affected nonroad diesel pool. This cost was applied to the volume of nonroad diesel fuel that would need to be desulfurized to meet the proposed 15 ppm standard beginning in June 2010.

7.3.2.3 Other Potential Distribution Costs Under the 15 ppm Sulfur Nonroad Diesel Fuel Program

We anticipate that there would be no other significant distribution costs associated with the adoption of the proposed 500 ppm non-highway diesel sulfur standard beyond those described in sections 7.3.1.1 & 2 above. As discussed in section 5.4 of this draft RIA, we do not expect the need for additional storage tanks beyond that discussed in section 7.3.1.2 above, an increase in pipeline downgrade or transmix volumes, or the need for additional facilities at the refinery to comply with the proposed fuel marker requirements.

Bulk plant operators who previously only handled high-sulfur heating oil would need to begin observing practices to limit sulfur contamination during the distribution of 1 ppm diesel fuel. However, these practices will be established well in advance as entities comply with the 15 ppm highway standard in 2006. These practices include purging storage tanks and fuel delivery systems of high-sulfur diesel fuel prior to the use of the equipment in handling 1500 ppm diesel fuel.. Training of employees would be necessary to impress the importance of consistently and carefully observing the practices to limit sulfur contamination. However, we estimate the costs associated would be minimal. In addition, we are estimating that most of the subject bulk plant operators would install dedicated storage tanks and truck delivery systems. This would obviate the need for much of the cautionary actions necessary to limit sulfur contamination when both low and high sulfur diesel fuel is carried by the same marketer.

As discussed in section 4.6 in this draft RIA, the vast majority of the fuel distribution system (primarily pipeline and terminal facilities) will already have optimized their facilities and procedures to limit sulfur contamination during the distribution of 15 ppm diesel fuel sulfur contamination due to the need to comply with the highway diesel fuel program in 2006. The costs associated with this optimization process were accounted for in the highway diesel program's RIA.[50] Highway diesel fuel and nonroad diesel fuel meeting a 15 ppm sulfur specification would share the same distribution system until nonroad diesel fuel would be dyed as it leaves the terminal to meet IRS requirements. Therefore, we do not expect there would be any additional actions and associated costs needed to optimize the distribution system to limit sulfur contamination during the distribution of 15 ppm nonroad diesel fuel.

A small fraction of bulk plant and tank truck operators who do not handle highway diesel may have had no prior experience in limiting sulfur contamination during the distribution of 15 ppm diesel fuel prior to the implementation of the proposed 15 ppm nonroad diesel sulfur standard in 2010. These would be the same entities that may have had no prior experience in distributing 500 ppm diesel fuel prior to the implementation of the 500 ppm NRLM sulfur standard in 2008. Consistent with the projections developed in the final highway diesel fuel rule regarding the handling practices for 15 ppm diesel fuel we believe that such entities would only need to more carefully and consistently observe standard industry practices regarding purging tanks and delivery lines of higher-sulfur product prior to the use in delivering 15 ppm nonroad diesel fuel.[51] Additional training may be needed of there operators to emphasize the criticality following such procedures. However, we believe that such training and the associated costs would be minimal.

7.3.3 Cost of Lubricity Additives

Our evaluation of the potential impact of the proposed non-highway diesel sulfur standards on fuel lubricity is contained in section 5.9 of this draft RIA. We concluded that the increased need for lubricity additives that would result from the adoption of these proposed sulfur standards would be similar to that for highway diesel fuel meeting the same sulfur standard.

The highway diesel final rule estimated that all diesel fuel meeting a 15 ppm sulfur standard would require the use of lubricity additives at a cost would be 0.2 cents per gallon.[52] As noted above, we concluded that the impact on fuel lubricity of meeting a 15 ppm sulfur standard for non-highway diesel fuel would be similar to that experienced in meeting15 ppm highway diesel sulfur standard. Therefore, consistent with the estimated cost due the increased use of lubricity additives in 15 ppm highway diesel fuel, we have included a charge of 0.2 cents per gallon in our cost calculation associated with today's action to account for cost for the increased use of lubricity additives in 15 ppm nonroad diesel fuel. This lubricity additive cost would be applicable to the affected nonroad diesel fuel pool beginning in 2010.

In estimating lubricity additive costs for 500 ppm diesel fuel we assumed that the same additive concentration needed in 15 ppm diesel fuel would also be needed in 500 ppm diesel fuel that needs such an additive, and that 5 percent of all 500 ppm diesel fuel would require a lubricity additive. Based on these assumptions, we estimate that the cost of additional lubricity additives for the affected 500 ppm NRLM diesel fuel would be 0.01 cents per gallon. The amount of lubricity additive needed increases substantially as diesel fuel is desulfurized to lower levels. Also, based on the industry input (see section 5.9 of this Draft RIA) it is likely that substantially less that 5 percent of 500 ppm diesel fuel outside of California requires a lubricity additive. Therefore, we believe that 0.01 cent per gallon represents a conservatively high estimate of the cost of lubricity additives for affected volume of 500 ppm nonroad, locomotive and marine diesel fuel. Although, the actual cost would likely be considerably less, we have no information with which to better quantify the percentage of 500 ppm diesel fuel that is currently treated with a lubricity additive or the appropriate additive treatment rate. Hence, it seems most appropriate to use an estimate that is conservatively high. The 0.01 cents per gallon lubricity additive cost would be applicable to the affected non-highway diesel pool (NRLM) until the proposed reduction in the sulfur standard for nonroad diesel fuel to 15 ppm would be implemented in 2010. After 2010, the 0.01 cents per gallon lubricity additive cost would be applicable to the affected locomotive and marine pool.

7.3.4 Fuel Marker Costs

Under the proposed requirement, high sulfur heating oil would be marked between 2007 and 2010 and locomotive and marine diesel fuel would be marked from 2010 until 2014. After 2014 the proposed marker requirement would expire.

Our conversations with marker manufactures indicate that the cost to treat fuel with either of the markers considered in the proposed rule would be lower than the costs to treat non-highway diesel fuel with red dye to meet IRS requirements. A major pipeline charges 0.2 cents per gallon to inject red dye to IRS specifications. We believe that this represents a conservatively high estimate of treatment costs for the markers under consideration. For the purposes of our cost calculations, we applied the annual cost of treating heating oil volumes with marker to the affected NRLM pool from June 2007 through June 2010. This results in a charge for the heating oil marker used during this time period of 0.16 cents per gallon of affected NRLM fuel. For the time period from June 2010 though June 2014 the cost of marking locomotive and marine diesel fuel was applied to the locomotive and marine pool itself. Thus, the marker costs during this time period are estimated at 0.2 cents per gallon of affected locomotive and marine diesel fuel. Please refer to section 7.1 of this draft RIA regarding the volume of 15 ppm diesel fuel we estimate would be used in locomotive and marine diesel fuel.

7.3.5 Distribution, Lubricity, and Marker Costs Under Alternative Sulfur Control Options

Distribution costs vary from 0.2 to 0.4 cents per gallon of affected diesel fuel under the alternative options considered. The variation in distribution cost is relatively insignificant compared to the variation in refining costs (see section 7.2 of this draft RIA).

Distribution costs vary due to differences in the volumetric energy density (VEC), marker and lubricity additive cost components. Under all of the alternative options considered the cost of additional storage tanks remains constant (0.1 cents per gallon).

Since the reduction in VEC is a side-effect of the desulfurization process, the increase in distribution costs associated it varies directly with the timing and applicability of the sulfur standards for NRLM. The earlier NRLM would be desulfurized, the earlier the charge for VEC must be applied. Since the reduction in VEC is higher in meeting a 15 ppm standard (0.07 cents per gallon) versus a 500 ppm standard (0.11 cents per gallon), costs related to reduced VEC increases if the 15 ppm sulfur standard would be more broadly applicable and/or the implementation of the standard would be earlier.

There is relatively little lubricity additive cost associated with desulfurization to meet a 500 ppm standard (0.01 cents per gallon) compared to that associated with desulfurization to meet a 15 ppm standard (0.2 cents per gallon). Consequently, distribution costs related to the need for additional lubricity additive increases if the 15 ppm sulfur standard would be more broadly applicable and/or the implementation of the standard would be earlier.

Marker related costs also vary based on the timing and applicability of the sulfur standards under consideration. Under some alternative options, marker costs apply for a longer or shorter duration and/or to a larger or smaller diesel pool.

A summary of the distribution costs under the various alternative options is presented in following table 7.3-2. A more complete discussion of the alternative options considered can be found in chapter 12 of this draft RIA. Please refer to section 7.1. regarding the volumes of fuel that these costs apply to. The net fuel related costs under the various sulfur control options under consideration is contained in section 7.5 of this draft RIA.

Table 7.3-2
Distribution and Additive Costs under Non-Highway Diesel Control Options (c/gal)[a]

Control Option	Sulfur Specifications	Year	Reduction in VEC	Additional Storage Tanks[b]	Additional Lubricity Additive	Marker[c]	Total Distribution & Additive Costs
Proposal	500 ppm NR, L & M	2007 - 2010	0.07	0.1	0.01	0.16	0.3
	500 ppm L & M	2010 - 2014	0.07	0.1	0.01	0.2	0.4
	15 ppm NR	2010 +	0.11	0.1	0.2	NA	0.4
	500 ppm L & M	2014 +	0.07	0.1	0.01	NA	0.2
Proposal with 15 ppm NR in 2009	500 ppm NR, L & M	2007 - 2009	0.07	0.1	0.01	0.16	0.3
	500 ppm L & M	2009 - 2013	0.07	0.1	0.01	0.2	0.4
	15 ppm NR (total incl 2007)	2009 +	0.11	0.1	0.2	NA	0.4
	500 ppm L & M	2013 +	0.07	0.1	0.01	NA	0.2
Proposal with NR, L & M to 15 ppm in 2010	500 ppm NR, L & M	2007 - 2010	0.07	0.1	0.01	0.16	0.3
	15 ppm NR, L & M (total incl 2007)	2010 +	0.11	0.1	0.2	NA	0.4

[a] Legend: NR= Nonroad diesel, L = Locomotive diesel, M = Marine diesel, VEC = Volumetric energy content
[b] Costs applied to “affected” gallons, i.e., gallons of fuel destined for a given end-use that would be desulfurized under given control option.
[c] When marker would be required in heating oil, costs are applied to affected NR, L, & M volume. When marker would be required in L &M, costs are applied to affected L, & M volume.

7.4 Net Cost of the Two-Step Nonroad Diesel Fuel Program

The estimated refining costs from Subsection 7.2.2 and distribution and additive costs from Sections 7.3 and 7.4 for the Proposed Nonroad Program and the other fuel options considered are summarized together in the following table. Both the 2007 and the 2010 costs are presented in the table. Note that these fuel costs do not include the impacts of the small refiner exemptions.

Table 7.4-1
Table of Fuel Costs for Nonroad Program Control Options (cents per gallon and $2002)

Option	Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
Proposal - Locomotive and Marine to 500 ppm and NR to 15 ppm	500 ppm NR, L & M	2007	2.2	0.3	2.5
	500 ppm L & M	2010	2.2	0.4	2.6
	15 ppm NR (total incl 2007)	2010+	4.4	0.4	4.8
	500 ppm L & M	2014+	2.2	0.2	2.4
One Step Locomotive & Marine to 500 ppm and NR to 15 ppm	500 ppm L & M	2008	2.2	0.4	2.5
	15 ppm NR	2008+	4.8	0.4	5.2
	500 ppm L & M	2012+	2.2	0.2	2.4
Nonroad goes to 15 ppm in 2009	500 ppm NR, L & M	2007	2.2	0.3	2.5
	500 ppm L & M	2009	2.2	0.4	2.5
	15 ppm NR (total incl 2007)	2009+	4.6	0.4	5.0
	500 ppm L & M	2013+	2.2	0.2	2.4
Nonroad, Locomotive and Marine go to 15 ppm	500 ppm NR, L & M	2007+	2.2	0.3	2.5
	15 ppm NR, L & M (total incl 2007)	2010+	4.6	0.4	5.0

Our projected total cost for producing 500 ppm fuel is essentially identical to the historical price differential between 500 ppm highway diesel and uncontrolled high sulfur diesel. This differential has averaged about 2.5 cents per gallon for the five year period from 1995 to 1999. Arguably, this differential would minimally account for refiners costs to hydrotreat and distribute a 500 ppm diesel fuel. While cost and prices are not always directly related, the fact that the two numbers are so closely aligned provides added assurance that our cost estimates are reasonable.

7.5 Potential Fuel Price Impacts

Transportation fuel prices are dependent on a wide range of factors, such as world crude oil prices, economic activity at the national level, seasonal demand fluctuations, refinery capacity utilization levels, processing costs, including fuel quality specifications, the cost of alternative energy sources (e.g., coal, natural gas), etc. Most of these factors would be unaffected by the proposed NRLM diesel fuel standards. However, a few, namely fuel processing costs and refinery capacity utilization could or would be affected by the proposed NRLM fuel program.

Fuel processing and distribution costs would clearly be affected due to the cost of desulfurizing NRLM diesel fuel to either the 500 or 15 ppm sulfur cap. Refinery utilization levels could be affected as the capacity to produce 500 ppm or 15 ppm NRLM diesel fuel would depend on refiners' investment in desulfurization capacity. The potential impact of increased fuel processing and distribution costs on the prices will be assessed below. The impact of the proposed rule on refinery utilization levels is beyond the scope of this analysis. In the long run, refiners would clearly invest to produce adequate volumes of NRLM diesel fuels, as well as other distillate fuels. In the shorter term, the issue of refiners' adequate investment in desulfurization capacity was already addressed in Chapter 5.9 above.

Two approaches to projecting future price impacts are evaluated here. The most direct approach to estimating the impact of the proposed NRLM fuel program on prices is to observe the price premiums commanded by similar products in the marketplace. This is feasible for 500 ppm NRLM diesel fuel, as both 500 ppm highway diesel fuel and high sulfur diesel fuel are both marketed today. As discussed in Section 7.2.2 above, the historical price premium of 500 ppm highway diesel fuel is 2.5 cents per gallon over that of high sulfur distillate. As this premium is essentially the same as our projected average total cost of the supplying 500 ppm NRLM diesel fuel, it represents one reasonable estimate of the future price impact of the 500 ppm NRLM diesel fuel standard.

It is not possible to use this methodology to project the price impact of the 15 ppm nonroad diesel fuel cap. Only a very limited amount of diesel fuel meeting a 15 ppm sulfur cap is marketed today in the U.S. This fuel is designed to be used in vehicle fleets which have been retrofitted with particulate traps. The fuel is produced in very limited quantities using equipment designed to meet the current EPA and California highway diesel fuel standards. It is also much more costly to distribute due to its extremely low volume. Thus, the current market prices for 15 ppm diesel fuel in the U.S. are not at all representative of what might be expected in 2010 under the proposed standard.

A greater volume, though still not large quantities, of 10 ppm sulfur diesel fuel is currently being sold in Europe. The great majority of this fuel is Swedish Class 1 (so-called City) diesel fuel, which is essentially a number one diesel fuel with very low aromatic content. The low aromatic specification significantly affects the cost of producing this fuel. Also, this fuel is generally produced using equipment not originally designed to produce 10-15 ppm sulfur fuel. Thus, as in the U.S., the prices paid for this fuel are not representative of what would occur in the U.S. in 2010. Therefore, we did not attempt to use fuels sold today which have sulfur levels similar to the standards we are proposing to evaluate our cost estimate for complying with the 15 ppm cap standard.

The other approach to project potential price impacts utilizes the projected costs to meet the 500 ppm and 15 ppm NRLM fuel sulfur caps. Both sulfur caps would affect fuel processing and distribution costs across the nation. (The exception would be California, where we presume that sulfur caps at least as stringent as those being proposed federally will already be in effect.) However, these costs appear to vary significantly from region to region. Because of the cost of fuel distribution and limited pipeline capacities (pipelines are the most efficient means of transporting fuel), the NRLM fuel markets, and those for other transportation fuels are actually regional in nature. Price differences can and usually do exist between the various regions of the country. Because of this, we have performed our assessment of potential price impacts on a regional basis. For the regions in our analysis, we have chosen PADDs. Practically speaking, there are probably more than five fuel markets in the U.S. with distinct prices. However, analyzing five distinct refining regions appears to provide a reasonable range of price impacts without adding precision that significantly exceeds our ability to project costs.

We made one exception to the PADD structure. PADD 3 (the Gulf Coast) supplies more high sulfur distillate to PADD 1, particularly the Northeast, than is produced by PADD 1 refineries. Two large pipelines connect PADD 3 refineries to the Northeast, the Colonial and the Plantation. Because of this low cost transportation connection, prices between the two PADDs are closely linked. We therefore combined our price analysis for PADDs 1 and 3.

As mentioned above, it is very difficult to predict fuel prices, either in the short term or long term. Over the past three years, transportation fuel prices (before excise taxes) have varied by a factor of two. Therefore, we have avoided any attempt to project absolute fuel prices. Because of the wide swings in absolute fuel prices, it is very difficult to assess the impact of individual factors on fuel price. The one exception is the price of crude oil, for two reasons. One, the cost of crude oil is the dominant factor in the overall cost of producing transportation fuels. Two, the pricing of essentially all crude oils is tied to the "world" market price of crude oil. While the cost of producing crude oil in each region of the world is independent of those of other crude oil, contract prices are tied to crude oils which are traded on the open market, such as West Texas Intermediate and North Sea Brent crude oils. Thus, as the price of world crude oil climbs, the price of gasoline and diesel fuel climb across the U.S., and vice versa. There is also a very rough correlation between refinery capacity utilization levels and fuel price. However, an unusually high availability of imports can cause prices to be relatively low despite high refinery capacity utilization rates in the U.S.

For example, fuel prices, as a function of crude oil price, have varied widely over the past decade. Refiner records supplied to EIA indicate that refiners' net refining margin has ranged from a low of $0.49 per barrel in 1992 to a high of 2.23 per barrel in 2000.[n] Thus, fuel prices have varied between being so low that refineries are barely covering their cash expenses to high enough to justify moderate cost increases in refining capacity (but not new refineries). The proposed NRLM rule would be very unlikely to have a major impact on factors such as these. Thus, projecting the likely price impact of the proposed rule is highly speculative. The best that can be done is to develop a wide range of potential price impacts indicative of the types of conditions which have existed in the past.

To do this, we developed three projections for the potential impact of the proposed fuel program on fuel prices. The lower end of the range assumes a very competitive NRLM fuel market with excess refining capacity. In this case, fuel prices within a PADD are generally low and only reflect incremental operating costs. Consistent with this, under this assumption, we project that the price of NRLM diesel fuel within a PADD would increase by the operating cost of the refinery with the highest operating cost in that PADD. This assumes that the refinery facing the highest operating cost in producing NRLM diesel fuel is setting the price of NRLM diesel fuel prior to this rule. This may or may not be the case. If not, the price increase could be even lower than that projected below. Under this "low cost" set of assumptions, the refiner with the highest operating cost would not recover any of his invested capital related to desulfurizing NRLM diesel fuel, but all other refiners would recover some of their investment.[o]

The mid-range estimate of price impacts could be termed the "full cost" scenario. It assumes that prices within a PADD increase by the average refining and distribution cost within that PADD, including full recovery of capital (at the societal rate of return of 7% per annum before taxes). Unlike the low and high price scenarios, the mid-range, full cost price scenario does not have a direct connection with economic pricing theory. It simply represents a convenient price estimate which falls between the low and high price estimates.

Under this full cost price scenario, lower cost refiners would recover their capital investment plus economic profit, while those with higher than average costs would recover some of their invested capital, but not all of it (i.e., at a lower rate of return than 7% per annum).

The high end estimate of price impacts assumes a NRLM fuel market that is constrained with respect to fuel production capacity. Prices rise to the point necessary to encourage additional desulfurization capacity. Also, prices are assumed to remain at this level in the long term, meaning that any additional desulfurization capacity brought on barely fulfills demand and does

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[N] Inflation adjusted dollars. EIA, Form EIA-28, Financial Reporting System, updated June 27, 2002.

[O] Theoretically, some refiners might recover all of their invested capital if their operating costs were sufficiently lower than those of the high cost refiner. However, practically, in the case of desulfurizing NRLM diesel fuel, this is highly unlikely.

not create an excess in capacity which would tend to reduce prices. However, prices should not increase beyond this level in the long run, as this would encourage the construction of additional desulfurization capacity, lowering prices. Consistent with this, prices within a PADD increase by the maximum total refining and distribution cost of any refinery within that PADD, including full recovery of capital (at 7% per annum before taxes). All other refiners would recover more than their capital investment.

The range of potential price increases resulting from these three sets of assumptions are shown in Table 7.5-1. The wholesale price of high sulfur distillate fuel has varied widely even over the past 12 months. The March 2003 heating oil futures price alone has ranged from 60-110 cents per gallon since early 2002. Assuming a base cost of NRLM fuel of one dollar per gallon, the increase in NRLM fuel prices would be equivalent to the price increase in terms of cents per gallon shown below.

Table 7.5-1
Range of Possible Total Diesel Fuel Price Increases (cents per gallon)[a]

	Low Price	Mid-Point	High Price
2007 500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel			
PADDs 1 and 3	0.9	1.5	3.4
PADD 2	2.3	3.0	4.8
PADD 4	1.7	4.1	5.8
PADD 5	1.0	2.8	4.3
2010 15 ppm Sulfur Cap: Nonroad Diesel Fuel			
PADDs 1 and 3	1.8	3.0	5.4
PADD 2	2.9	6.1	7.4
PADD 4	3.0	8.9	9.3
PADD 5	1.7	5.9	8.4

[a] At a wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

Under the low price scenario, the price of nonroad, locomotive and marine diesel fuel would increase in 2007 by 1-2 cents per gallon, depending on the area of the country. In 2010, the price of nonroad diesel fuel would increase a total of 2-3 cents per gallon. Locomotive and marine diesel fuel prices would continue to increase by 1-2 cents per gallon.

Under the mid-point price scenario, the price of nonroad, locomotive and marine diesel fuel would increase in 2007 by 2-4 cents per gallon, depending on the area of the country. In 2010, the price of nonroad diesel fuel would increase a total of 3-9 cents per gallon. Locomotive and marine diesel fuel prices would continue to increase by 2-4 cents per gallon.

Under the high price scenario, the price of nonroad, locomotive and marine diesel fuel would increase in 2007 by 3-6 cents per gallon, depending on the area of the country. In 2010, the price of nonroad diesel fuel would increase a total of 5-9 cents per gallon. Locomotive and marine diesel fuel prices would continue to increase by 3-6 cents per gallon.

Appendix 7A: Estimated Total Off-Highway Diesel Fuel Demand and Diesel Sulfur Levels

Table 7A-1 was used to derive Table 7.1-3.

Table 7A-1
Estimated Total Non-Highway Diesel Fuel Demand[a]

Category	Area	No. 1	L.S. Diesel	Diesel	No. 2 F.O.	Distillate F.O.	Total Distillate	Other Distillate	H.S. Diesel	Total*
Total	US	0.236	1.871	3.260	8.019	8.961	0.000	0.143	1.363	23.853
	California	0.001	0.122	0.261	0.010	0.520	0.000	0.000	0.007	0.921
	Alaska	0.043	0.004	0.006	0.041	0.160	0.000	0.000	0.000	0.254
	Hawaii	0.000	0.004	0.019	0.000	0.106	0.000	0.000	0.000	0.129
	49 State	0.235	1.749	2.999	8.009	8.441	0.000	0.143	1.248	22.824
	PADD I	0.012	0.534	0.430	6.914	1.984	0.000	0.073	0.500	10.447
	PADD II	0.134	0.452	1.587	0.770	2.318	0.000	0.061	0.438	5.760
	PADD III	0.004	0.339	0.558	0.147	2.992	0.000	0.003	0.276	4.319
	PADD IV	0.033	0.271	0.221	0.045	0.563	0.000	0.004	0.034	1.171
	PADD V	0.053	0.274	0.462	0.144	1.103	0.000	0.002	0.115	2.153
Residential	US	0.118			6.086					6.204
	California	0.000			0.007					0.007
	Alaska	0.023			0.025					0.048
	Hawaii				0.000					0.000
	49 State	0.118	0.000	0.000	6.079	0.000	0.000	0.000	0.000	6.197
	PADD I	0.008			5.391					5.399
	PADD II	0.072			0.557					0.629
	PADD III	0.000			0.001					0.001
	PADD IV	0.009			0.030					0.039
	PADD V	0.029			0.108					0.137
Commercial	US	0.064	1.061		1.576				0.474	3.175
	California	0.000	0.079		0.003				0.005	0.087
	Alaska	0.01	0.004		0.012					0.026
	Hawaii		0.003		0.000					0.003
	49 State	0.064	0.982	0.000	1.573	0.000	0.000	0.000	0.446	3.065
	PADD I	0.003	0.418		1.304				0.219	1.944
	PADD II	0.036	0.276		0.102				0.153	0.567
	PADD III	0.001	0.146		0.142				0.058	0.347
	PADD IV	0.011	0.069		0.007				0.016	0.103
	PADD V	0.013	0.151		0.021				0.028	0.213
Industrial	US	0.054	0.81		0.357				0.889	2.110
	California	0.000	0.043		0.000				0.002	0.045
	Alaska	0.01	0.00002		0.004					0.014
	Hawaii		0.001		0.000					0.001
	49 State	0.054	0.767	0.000	0.357	0.000	0.000	0.000	0.802	1.980
	PADD I	0.001	0.116		0.219				0.281	0.617
	PADD II	0.026	0.176		0.111				0.285	0.598
	PADD III	0.003	0.193		0.004				0.218	0.418
	PADD IV	0.013	0.202		0.008				0.018	0.241
	PADD V	0.011	0.123		0.015				0.087	0.236

Category	Area	No. 1	L.S. Diesel	Diesel	No. 2 F.O.	Distillate F.O.	Total Distillate	Other Distillate	H.S. Diesel	Total*
Oil Company	US					0.685				0.685
	California					0.006				0.006
	Alaska					0.026				0.026
	Hawaii					0.000				0.000
	49 State	0.000	0.000	0.000	0.000	0.679	0.000	0.000	0.000	0.679
	PADD I					0.019				0.019
	PADD II					0.042				0.042
	PADD III					0.561				0.561
	PADD IV					0.029				0.029
	PADD V					0.034				0.034
Farm	US			3.08				0.089		3.169
	California			0.254				0.000		0.254
	Alaska			0.00003						0.000
	Hawaii			0.008						0.008
	49 State	0.000	0.000	2.826	0.000	0.000	0.000	0.089	0.000	2.915
	PADD I			0.389				0.044		0.433
	PADD II			1.572				0.040		1.612
	PADD III			0.549				0.003		0.552
	PADD IV			0.219				0.002		0.221
	PADD V			0.351				0.000		0.351
Electric Utility	US					0.793				0.793
	California					0.008				0.008
	Alaska					0.036				0.036
	Hawaii					0.09				0.090
	49 State	0.000	0.000	0.000	0.000	0.785	0.000	0.000	0.000	0.785
	PADD I					0.305				0.305
	PADD II					0.134				0.134
	PADD III					0.195				0.195
	PADD IV					0.009				0.009
	PADD V					0.151				0.151
Railroad	US					3.071				3.071
	California					0.189				0.189
	Alaska					0.004				0.004
	Hawaii									0.000
	49 State	0.000	0.000	0.000	0.000	2.882	0.000	0.000	0.000	2.882
	PADD I					0.5				0.500
	PADD II					1.233				1.233
	PADD III					0.686				0.686
	PADD IV					0.345				0.345
	PADD V					0.307				0.307
Vessel*	US					2.081				2.081
	California					0.101				0.101
	Alaska					0.08				0.080
	Hawaii					0.013				0.013
	49 State	0.000	0.000	0.000	0.000	1.980	0.000	0.000	0.000	1.980
	PADD I					0.49				0.490
	PADD II					0.301				0.301

Category	Area	No. 1	L.S. Diesel	Diesel	No. 2 F.O.	Distillate F.O.	Total Distillate	Other Distillate	H.S. Diesel	Total*
	PADD III					1.033				1.033
	PADD IV					0.0002				0.000
	PADD V					0.256				0.256
Military	US			0.18				0.054		0.234
	California			0.007				0.000		0.007
	Alaska			0.006				0.00005		0.006
	Hawaii			0.011						0.011
	49 State	0.000	0.000	0.173	0.000	0.000	0.000	0.054	0.000	0.227
	PADD I			0.041				0.029		0.070
	PADD II			0.015				0.021		0.036
	PADD III			0.009				0.000		0.009
	PADD IV			0.002				0.002		0.004
	PADD V			0.111				0.002		0.113
Construction	US					1.9				1.900
	California					0.194				0.194
	Alaska					0.007				0.007
	Hawaii					0.003				0.003
	49 State	0.000	0.000	0.000	0.000	1.706	0.000	0.000	0.000	1.706
	PADD I					0.511				0.511
	PADD II					0.549				0.549
	PADD III					0.394				0.394
	PADD IV					0.15				0.150
	PADD V					0.295				0.295
Other Off High	US					0.431				0.431
	California					0.022				0.022
	Alaska					0.007				0.007
	Hawaii					0.000				0.000
	49 State	0.000	0.000	0.000	0.000	0.409	0.000	0.000	0.000	0.409
	PADD I					0.159				0.159
	PADD II					0.059				0.059
	PADD III					0.123				0.123
	PADD IV					0.03				0.030
	PADD V	0.000				0.06				0.060

[a] Energy Information Administration. *Fuel Oil and Kerosene Sales 2000*. DOE/EIA-0535(00). Office of Oil and Gas, U.S. Department of Energy. Washington, D. C. September, 2001.

The information in Tables 7A-2 through 7A-7 was used to derive Table 7.1-21

Table 7A-2
1996 Off-highway Diesel Sulfur Levels from TRW (Niper)

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
39	Eastern	B1	1	SM	1,500,000	1700	2,550,000,000
40	Eastern	B1, D1	1	RR, SM	1,500,000	4000	6,000,000,000
41	Eastern	C2	1	TT	500,000	1800	900,000,000
42	Eastern	C1, E3	1	RR, SM	1,500,000	3700	5,550,000,000
43	Eastern	C2, E3	1	RR, SM	1,000,000	2900	2,900,000,000
45	Southern	D1	1	TT	750,000	4330	3,247,500,000
46	Southern	D1	1	TT	750,000	4900	3,675,000,000
47	Southern	D3	1	SM	137,500	9600	1,320,000,000
48	Eastern	D, B, C, A	1	SM, RR		1600	
					7,637,500		3,423
41	Eastern	C2	2	TT	500,000	1800	900,000,000
42	Central	C1, E3	2	RR, SM	275,000	3700	1,017,500,000
43	Central	C2, E3	2	RR, SM	275,000	2900	797,500,000
48	Eastern	D, B, C, A	2	SM, RR		1600	
49	Central	F1, E3	2	RR, SM	1,775,000	4200	7,455,000,000
50	Central	G	2			2050	
51	Central	G	2			1640	
					2,825,000		3,600
40	Southern	B1, D1	3	SM	1,500,000	4000	6,000,000,000
45	Southern	D1	3	TT	750,000	4330	3,247,500,000
46	Southern	D1	3	TT	750,000	4900	3,675,000,000
47	Southern	D3	3	SM	137,500	9600	1,320,000,000
48	Southern	D, B, C, A	3	RR, SM		1600	
					3,137,500		4,539
52	Rocky Mtn	K3, L3, M3	4	TT	412,500	4100	1,691,250,000
					412,500		4,100
52	Western	K3, L3, M3	5	TT	412,500	4100	1,691,250,000
53	Western	M1	5	TT	1,500,000	2700	4,050,000,000
					1,912,500		3,002
			National		15,925,000		3,641

Table 7A-3
1997 Off-highway Diesel Sulfur Levels from TRW (Niper)

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
47	Eastern	B	1			1900	
48	Eastern	B, D	1	SM		1200	
49	Eastern	B1	1	SM	1,500,000	1600	2,400,000,000
50	Eastern	B1, D1	1	RR, SM	2,250,000	4000	9,000,000,000
51	Eastern	C1, E3	1	RR, SM	750,000	4100	3,075,000,000
52	Eastern	C2	1	TT	750,000	2000	1,500,000,000
53	Eastern	C2, E3	1	RR, SM	750,000	3220	
					6,000,000		2,663
51	Central	C1, E3	2	RR, SM	1,025,000	4100	4,202,500,000
52	Central	C2	2	TT	500,000	2000	1,000,000,000
53	Central	C2, E3	2	RR, SM	775,000	3220	2,495,500,000
57	Southern	D1, G2	2	TT	1,000,000	1640	1,640,000,000
60	Central	F1, E3	2	RR, SM	1,775,000	3360	5,964,000,000
61	Central	G	2	RR		2160	
					2,775,000		2,740
48	Southern	B, D	3	SM		1200	
50	Southern	B1, D1	3	RR, SM	750,000	4000	3,000,000,000
55	Southern	D1	3	TT	750,000	5000	3,750,000,000
56	Southern	D1	3	TT	750,000	3460	2,595,000,000
57	Southern	D1, G2	3	TT	750,000	1640	1,230,000,000
58	Southern	D2	3	RR, SM	500,000	4800	2,400,000,000
59	Southern	D3	3	SM	137,500	10000	1,375,000,000
					3,637,500		3,945
63	Rocky Mtn	K3, L3, M3	4	TT	275,000	1000	275,000,000
					275,000		1,000
63	Western	K3, L3, M3	5	TT	550,000	1000	550,000,000
64	Western	M1, N1	5	TT	3,000,000	2500	7,500,000,000
					3,550,000		2,268
			National		16,237,500		2,849

Table 7A-4
1998 Off-highway Diesel Sulfur Levels from TRW (Niper)

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
43	Eastern	B	1	TT		1600	
44	Eastern	B2	1	SM	1,000,000	1540	1,540,000,000
45	Eastern	C2, E2	1		500,000	2600	1,300,000,000
48	Southern	D1	1	TT	750,000	4900	3,675,000,000
49	Southern	D1	1	RR, SM	750,000	3870	2,902,500,000
50	Southern	D1	1	TT	750,000	1300	975,000,000
51	Southern	D1, G2	1	RR, SM	750,000	10000	7,500,000,000
52	Southern	D3	1		137,500	4700	646,250,000
					4,637,500		3,998
45	Central	C2, E2	2		1,500,000	2600	3,900,000,000
50	Central	D1, G2	2	TT	1,000,000	1300	1,300,000,000
53	Central	F3	2		275,000	3700	1,017,500,000
					1,275,000		1,818
48	Southern	D1	3	TT	750,000	4900	3,675,000,000
49	Southern	D1	3	RR, SM	750,000	3870	2,902,500,000
50	Southern	D1	3	TT	750,000	1300	975,000,000
51	Southern	D1, G2	3	RR, SM	750,000	10000	7,500,000,000
52	Southern	D3	3		137,500	4700	646,250,000
					3,137,500		5,004
73	Rocky Mtn	K3, L3, M3	4	TT	275,000	3400	935,000,000
					275,000		3,400
73	Western	K3, L3, M3	5	TT	550,000	3400	1,870,000,000
74	Western	M2	5	TT	1,000,000	2900	2,900,000,000
					1,550,000		3,077
			National		10,875,000		3,886

Table 7A-5
1999 Off-highway Diesel Sulfur Levels from TRW (Niper)

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
65	Eastern	B2	1	SM	1,000,000	1560	1,560,000,000
66	Eastern	C3	1		137,500	4950	680,625,000
67	Southern	D1	1	SM, RR	750,000	4290	3,217,500,000
68	Southern	D1	1	TT	750,000	4590	3,442,500,000
69	Southern	D1	1	TT	750,000	4900	3,675,000,000
70	Southern	D1, E1, G2	1	TT	750,000	1200	900,000,000
71	Southern	D3	1	RR, SM	137,500	10000	1,375,000,000
					4,275,000		3,474
66	Eastern	C3	2		137,500	4950	680,625,000
70	Central	D1, E1, G2	2	TT	2,500,000	1200	3,000,000,000
72	Central	F3	2		275,000	4800	1,320,000,000
					2,912,500		1,717
44	Southern	D1	3	TT	750,000	4900	3,675,000,000
45	Southern	D1	3	SM, RR	750,000	4113	3,084,750,000
67	Southern	D1	3	SM, RR	750,000	4290	3,217,500,000
68	Southern	D1	3	TT	750,000	4590	3,442,500,000
69	Southern	D1	3	TT	750,000	4900	3,675,000,000
70	Southern	D1, E1, G2	3	TT	750,000	1200	900,000,000
71	Southern	D3	3	RR, SM	137,500	10000	1,375,000,000
					4,637,500		4,177
73	Rocky Mtn	K3, L3, M3	4	TT	275,000	2000	550,000,000
					275,000		2,000
73	Western	K3, L3, M3	5	TT	550,000	2000	1,100,000,000
74	Western	M2	5	TT	1,000,000	2100	2,100,000,000
					1,550,000		2,065
			National		13,650,000		3,148

Table 7A-6
2000 Off-highway Diesel Sulfur Levels from TRW (Niper)

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
37	Eastern	B	1			1370	
38	Eastern	B2	1	TT	1,000,000	3000	3,000,000,000
39	Eastern	B2	1	TT	1,000,000	2900	2,900,000,000
40	Eastern	B2	1	SM	1,000,000	1280	1,280,000,000
41	Eastern	C1	1	TT, RR	750,000	3600	2,700,000,000
42	Eastern	C2, E2	1		500,000	7200	3,600,000,000
43	Eastern	C3	1		137,500	4240	583,000,000
44	Southern	D1	1	TT	750,000	4900	3,675,000,000
45	Southern	D1	1	SM, RR	750,000	4113	3,084,750,000
46	Southern	D1, E1, G2	1	TT	750,000	1150	862,500,000
47	Southern	D2	1	TT	500,000	3100	1,550,000,000
48	Southern	D2	1	RR, SM	500,000	9800	4,900,000,000
49	Southern	D2	1	TT, RR	500,000	4440	2,220,000,000
50	Southern	D3	1		137,500	4800	660,000,000
51	Eastern	E1, C1	1	TT, RR	750,000	2600	1,950,000,000
					9,025,000		3,653
41	Eastern	C1	2	TT, RR	750,000	3600	2,700,000,000
42	Central	C2, E2	2		1,500,000	2200	3,300,000,000
43	Eastern	C3	2		137,500	4240	583,000,000
46	Central	D1, E1, G2	2	TT	2,500,000	1150	2,875,000,000
51	Central	E1, C1	2	TT, RR	2,250,000	2600	5,850,000,000
52	Central	F3	2		275,000	4120	1,133,000,000
53	Central	G1, E1	2	TT, RR	3,000,000	4720	14,160,000,000
					10,412,500		2,939
44	Southern	D1	3	TT	750,000	4900	3,675,000,000
45	Southern	D1	3	SM, RR	750,000	4113	3,084,750,000
46	Southern	D1, E1, G2	3	TT	750,000	1150	862,500,000
47	Southern	D2	3	TT	500,000	3100	1,550,000,000
48	Southern	D2	3	RR, SM	500,000	9800	4,900,000,000
49	Southern	D2	3	TT, RR	500,000	4440	2,220,000,000
50	Southern	D3	3		137,500	4800	660,000,000
					3,887,500		4,361
60	Rocky Mtn	K3	4	TT	275,000	2600	715,000,000
					275,000		2,600
1996 Off-highway Diesel Sulfur Levels from TRW (Niper)							
52	Western	K3, L3, M3	5	TT	412,500	4100	1,691,250,000
53	Western	M1	5	TT	1,500,000	2700	4,050,000,000
					1,912,500		3,002
			National		25,512,500		3,409

Table 7A-7
2001 Off-highway Diesel Sulfur Levels from TRW (Niper) 14 samples total

Sample	Region	District	PADD	Use Category	Presumed Volume	Sulfur, ppm	Sulfur * Volume
48	Eastern	B2	1	SM	1,000,000	1560	1,560,000,000
49	Eastern	B3	1	TT	275,000	1600	440,000,000
50	Eastern	C1	1	TT	750,000	3020	2,265,000,000
51	Eastern	C2, E2	1		1,000,000	3000	3,000,000,000
52	Eastern	C3	1		137,500	1360	187,000,000
53	Southern	D1	1	SM, RR	750,000	4330	3,247,500,000
54	Southern	D1	1	TT	750,000	4600	3,450,000,000
55	Southern	D3	1		137,500	4980	684,750,000
56	Southern	D3	1	TT	137,500	1800	247,500,000
					4,937,500		3,055
50	Eastern	C1	2	TT	750,000	3020	2,265,000,000
51	Central	C2, E2	2		1,000,000	3000	3,000,000,000
52	Central	C3	2		137,500	1360	187,000,000
57	Central	E4	2	TT	50,000	3100	155,000,000
58	Central	F3	2		275,000	4150	1,141,250,000
59	Central	G1, E1	2	TT, RR	3,000,000	4590	13,770,000,000
					5,212,500		3,936
53	Southern	D1	3	SM, RR	750,000	4330	3,247,500,000
54	Southern	D1	3	TT	750,000	4600	3,450,000,000
55	Southern	D3	3		137,500	4980	684,750,000
56	Southern	D3	3	TT	137,500	1800	247,500,000
					1,775,000		4,298
60	Rocky Mtn	K3	4		275,000	2340	643,500,000
					275,000		2,340
1996 Off-highway Diesel Sulfur Levels from TRW (Niper)							
52	Western	K3, L3, M3	5	TT	412,500	4100	1,691,250,000
53	Western	M1	5	TT	1,500,000	2700	4,050,000,000
					1,912,500		3,002
			National		14,112,500		3,516

Appendix 7B: Land-Based Nonroad Engine Growth Rate Based on Annual Energy Outlook 2002

Table 7.B-1
2000-2008 Composite Growth Factor for Land-Based Nonroad Engines
Based on Annual Energy Outlook 2002 (AEO2002)

End Use	2000 Land-Based Nonroad Diesel Demand (million gallons)	Fraction of Total	2000-2008 Multiplicative Growth Factor	Consumption Weighted Multiplicative Growth Factor	% Simple Annual Growth Rate	Source of Energy Consumption
Commercial	488	0.059	1.105	0.065	--	Diesel demand from Table 7.1-8;, Growth factor from AEO2002, Table 2, Commercial, Distillate Fuel
Industrial	1721	0.208	1.063	0.222	--	Diesel demand from Table 7.1-8; Growth factor from AEO2002, Table 2, Industrial, Distillate Fuel
Farm	3080	0.373	1.039	0.388	--	Diesel demand from Table 7.1-8; Growth factor from AEO2002, Table 32, Agriculture, Distillate Fuel
Construction	1805	0.219	1.138	0.249	--	Diesel demand from Table 7.1-8;, Growth factor from AEO2002, Table 32, Construction, Distillate Fuel
Railroad	29	0.004	1.083	0.004	--	Diesel demand from Table 7.1-8;, Growth factor from AEO2002, Table 7, Energy Use by Mode, Railroad
Military	153	0.019	1.000	0.019	--	Diesel demand from Table 7.1-8, Assumed no growth due to base closings and no information suggesting long term increases in training or emergency operations
Other Non-Highway	409	0.050	1.074	0.053	--	Diesel demand from Table 7.1-8, Growth factor from Table 7.1-15
Oil Company	342	0.041	1.074	0.044	--	Assumed same as Other Non-Highway
On-Highway	229	0.028	1.238	0.034	--	Diesel demand from Table 7.1-8; Growth factor from AEO2002, Table 7, Energy Use by Mode, Freight Trucks (over 10,000 lbs. GVWR.
Composite Average				**1.078**	**0.97**	

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